APPENDIX F6 – RESOURCE OPTIONS

I. INTRODUCTION

The main goal of resource planning is to evaluate the size, type, timing and sometimes location of resources we plan to procure to meet customer needs over the next several years. To do this, we take into account key planning considerations, such as carbon reduction goals, reliability, affordability and potential future risk. Over the course of the 2020-2034 planning horizon, our customers' gross peak demand needs are expected to grow from approximately 10,500 MW to just over 11,700 MW, before accounting for Demand Side Management (DSM) adjustments. While we are currently long capacity, a substantial portion of our resources will either reach planned retirement or end of contract dates over the planning period, per our Preferred Plan. As a result, our modeling shows a capacity deficiency in the mid-2020s timeframe. Our Resource Plan addresses how the Company proposes to fill this gap by identifying an appropriate mix of future resource additions.

To identify this mix the Company developed a set of generic resources for inclusion in Strategist modeling, with size, cost, and performance assumptions that reflect updated information from project experience, public stakeholder meeting input, and independent third party studies. Future resource options can be generally categorized as supply-side resources, and demand-side resources. We also evaluated potential transmission cost implications associated with supply-side centralized resources, given current transmission capacity constraints in MISO. Paired with existing owned resources and contracts, this set of generic resources was evaluated in Strategist modeling to determine optimal future resource portfolios, in light of the different scenarios and sensitivities we tested.

II. EXISTING RESOURCES

The Company owns and has under contract approximately 13,500 MW of capacity currently, although as stated above, many of our current resources are slated to retire over the planning period. Below we include discussion of each resource type, and tables showing: each generating unit, whether it is owned or contracted, capacity we own or contract,[1] and the retirement year if known, as reflected in the Strategist model. These numbers have been rounded to the nearest whole number for simplicity, where applicable. It should be noted that the capacity numbers provided below are the maximum values included in the Strategist modeling, and may differ

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[1] Expected as of 2020.

marginally from official nameplate or ICAP values.

A. Coal

The Company owns and operates four coal-fired power plants, with a total capacity of 2,390 MW. Planned retirement dates for Sherco 1 in 2026 and Sherco 2 in 2023 were approved in our last Resource Plan, and existing retirement dates for King and Sherco 3 are 2037 and 2040 respectively. As part of our Preferred Plan, we are proposing to retire these two facilities a decade early; where AS King and Sherco 3 would retire in in 2028 and 2030, respectively.

Table 1: Existing Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Allen S King	Steam Turbine (ST)	Own	511	2037
Sherco 1	ST	Own	680	2026
Sherco 2	ST	Own	682	2023
Sherco 3[2]	ST	Own	517	2040

B. Nuclear

The Company owns and operates three nuclear power plants with a total capacity of 1,738 MW. These units operate at very high capacity factors and provide nearly 30 percent of the energy for our system. They have also both achieved operating costs reductions of over 20 percent from 2015 levels, and both produce energy for our system for under $30/MWh. The existing retirement dates for the nuclear facilities are reflected in the table below. In our Preferred Plan, we propose to extend Monticello plant operation to 2040.

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[2] This represents the portion of Sherco 3 under our ownership.

Table 2: Existing Nuclear Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Monticello	Boiling Water Reactor	Own	646	2030
Prairie Island 1	Pressurized Water Reactor (PWR)	Own	546	2033
Prairie Island 2	PWR	Own	546	2034

C. Natural Gas and Oil

The Company owns or maintains Purchase Power Agreements (PPAs) with many natural gas facilities. Our current natural gas generators are configured as either simple-cycle Combustion Turbines (CTs) or a Combined Cycle Gas Turbine (CCGTs or CCs). The CTs are located at seven different sites and provide peaking capacity meaning they are only typically dispatched a limited number of times a year during peak demand and/or net load conditions. The CCs are located at five sites and provide intermediate capacity, meaning they tend to operate at higher capacity factors due to better efficiencies and lower dispatch prices when compared to CTs.

Our current natural gas and oil fleet provides nearly 4,780 MW of dispatchable capacity. Resource portfolio provides a combined with varying retirement dates In the list of resource below, we provide the capacity and anticipated retirement dates for the Mankato CC assuming we own the resource, per our proposed acquisition in Docket No. IP6949, E002/PA-18-702; however, the Company currently has a PPA for energy and capacity with each of the Mankato CC units. The second unit began commercial operation in June 2019.

Table 3: Existing Natural Gas and Oil Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity	Existing or Planned Retirement/Contract Expiration
Black Dog 52	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center[3]	CC	Own	762	2046, 2054
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-4	CT	Own	386	2034
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2034
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	Oil	Own	191	2023
French Island 3,4	Oil	Own	160	2027
Wheaton 6	Oil	Own	70	2025

D. Biomass

The company owns and operates, and maintains PPAs with, various biomass facilities. Refuse-derived fuel (RDF), landfill (LND) and digester (DIGT) resources are also generally considered biomass resources and therefore included in this category. These facilities total nearly 160 MW of capacity on our system.

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[3] Note: As stated above, we have modeled Mankato Energy Center as an owned resource. Approval of this acquisition is pending in Docket No. IP6949, E002/PA-18-702.

Table 4: Existing Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Bayfront 5,6	Bio	Own	26	2035
French Island 1,2	Bio	Own	15	2027
Red Wing 1,2	Bio	Own	18	2027
Wilmarth 1,2	Bio	Own	17	2027
KODA Energy	Bio	PPA	12	2019
St. Paul Cogen	Bio	PPA	24	2023
WM Renewable Energy	LND	PPA	4	2020
Gunderson	LND	PPA	1	
Barron County	RDF	PPA	2	2022
Hennepin Energy Recovery Center	RDF	PPA	34	2024
Diamond K. Dairy[4]	DIGT	PPA	0.4	2023
Greenwhey	DIGT	PPA	3	
Heller Dairy	DIGT	PPA	0.5	

E. Hydroelectric

The Company owns, operates and maintains PPAs for hydropower resources with a number of different counterparties, totaling over 680 MW. The majority of our current hydro capacity is provided by our PPAs with Manitoba Hydro, which expire in 2025. We also have an additional 125 MW PPA with Manitoba Hydro that is slated to start in 2021. Further, the Company has a 350 MW Diversity Agreement with Manitoba Hydro, wherein we receive 350 MW of capacity in the summer and Manitoba Hydro receives 350 MW of capacity in the winter. Due to the unique nature of the agreement, it is not included in the list below or reflected in the total hydro capacity specified above.

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[4] Note: This unit is included in Strategist modeling, but its PPA was terminated as of April 2019.

Table 5: Existing Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Byllesby	Hydro	PPA	2	2021
Hastings	Hydro	PPA	4	2033
St. Cloud	Hydro	PPA	9	2021
Dairyland	Hydro	PPA	4	-
Eau Galle	Hydro	PPA	0.3	2026
DG Hydro	Hydro	PPA	0.4	-
LCO Hydro	Hydro	PPA	3	2021
Neshonoc	Hydro	PPA	0.4	2020
Rapidan	Hydro	PPA	5	2020
SAF Hydro	Hydro	PPA	9	2031
WTC Angelo Dam	Hydro	PPA	0.2	2024
MN Grouped Hydro	Hydro	Own	14	-
WI Grouped Hydro	Hydro	Own	260	-
Manitoba Hydro	Hydro	PPA	371	2025
Manitoba Hydro	Hydro	PPA	125	2025 (2021 start)

F. Wind

The Company owns or contracts for over 2,600 MW of wind power. Over the next two to three years, the Company intends to add 1,850 MW of wind generation from recent acquisitions and Requests for Proposal (RFPs), as well additional capacity to serve other customer programs.

Table 6: Existing and Near Term Wind Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Big Blue	Wind	PPA	36	2032
Chanarambie	Wind	PPA	86	2023
Community Wind North	Wind	PPA	26	2044
Fenton	Wind	PPA	206	2032
McNeilus Group	Wind	PPA	37	2028
Jeffers	Wind	PPA	44	2044
MinnDakota	Wind	PPA	150	2022
Moraine II	Wind	PPA	50	2029
Community Wind South (Zephyr)	Wind	PPA	31	2032
Lake Benton I	Wind	PPA	104	2028
Lake Benton II[5]	Wind	PPA	104	2019
Odell	Wind	PPA	200	2035
Prairie Rose	Wind	PPA	200	2032
FPL Mower Co	Wind	PPA	99	2026
Ridgewind	Wind	PPA	25	2031
Border	Wind	Own	150	2040
Courtenay	Wind	Own	200	2041
Grand Meadows	Wind	Own	100	2033
Nobles	Wind	Own	200	2035
Pleasant Valley	Wind	Own	200	2040
Crowned Ridge (Owned)	Wind	Own	300	2044
Freeborn	Wind	Own	200	2045
Foxtail	Wind	Own	150	2044
Blazing Star I	Wind	Own	200	2044
Blazing Star II	Wind	Own	200	2045
Lake Benton Repower	Wind	Own	100	2044
Dakota Range 1 & 2	Wind	Own	300	2046
Dakota Range 3	Wind	PPA	150	2032
Clean Energy	Wind	PPA	100	2039
Crowned Ridge (PPA)	Wind	PPA	300	2044
Small Wind[6]	Wind	PPA	285	Various

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[5] Note: this unit is being repowered; the repower is reflected as a separate line item in this table ("Lake Benton Repower").

[6] Includes PPAs of 20 MW or less

G. Solar

By 2020 the Company anticipates it will maintain a total of 990 MW of solar capacity, via PPA, to serve our customers. This includes approximately 260 MW of large grid-scale solar, over 640 MW of Community Solar Gardens (anticipated by 2020), and nearly 90 MW of small-scale distributed solar.

Table 7: Existing Solar Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Slayton	PV	PPA	2	2033
St. John's	PV	PPA	0.4	2030
School Sisters of Notre Dame	PV	PPA	0.7	2036
Other RDF Solar	PV	PPA	2	
Aurora	PV	PPA	99	2036
Marshall	PV	PPA	62	2042
North Star	PV	PPA	99	2041
DG Solar[7]	PV		86 (2020)	Various
Community Solar Garden	PV	PPA	641(2020)	Various

III. GENERIC FUTURE RESOURCE OPTIONS

Consistent with past resource plans, we have developed generically-defined resources to use in Strategist modeling, from which the model can select when resource retirements or PPA expirations result in our remaining portfolio falling short of future projected demand. Cost and performance data for these resources was developed using a mix of third party studies and forecasts such as the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), consultant estimates, and internal Company data. Generic resources are intended to help identify the general size, type, and timing of resource needs in the future and do not typically represent a specific resource at a specific location, or whether such a resource would be owned or contracted. Rather, these specific details are determined via a competitive acquisition process that is held after the general size, type and timing has been established and approved in the Resource Plan proceeding.

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[7] Includes Solar*Rewards and Made in MN Solar

It is important to highlight that the Company worked closely with and solicited feedback from stakeholders to select the best sources and methodologies to employ in developing generic resource options. Our stakeholder interactions, and direction from our regulators, resulted in a number of refinements to our past assumptions. We believe these adjustments improved the quality of our modeling and highlight the benefit of our proactive approach to stakeholder engagement.

A. Supply Side Resources

Supply-side centralized resources are traditional large-scale thermal and renewable generation facilities. We have included a number of supply-side centralized fuel types in our modeling; large-scale wind and solar, a variety of natural gas resource options, and battery energy storage. Their attributes, and the method by which we developed each one, are described further. We also detail specific resource cost and performance assumptions in Appendix F2, unless otherwise noted.

1. Wind

Our generic wind resource option was sized at 750 MW on nameplate capacity basis. While the size of this generic wind resource may seem relatively large, we account for the MISO accredited capacity value for new wind resources as 15.6 percent[8] of this total, or about 117 MW. Given our modeling selects resources on the basis of their accredited capacity, and given the size of our system, and magnitude of future capacity needs, we feel this sizing represents an appropriate approach to modeling generic wind additions.

We derived forecasted wind costs used in our modeling from publicly available data from the NREL 2018 ATB Levelized Cost of Electricity (LCOE) data. This cost has been further adjusted for tax credit effects in relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with a greenfield generation facility, as described further below.

2. Solar

Our generic supply-side large-scale solar resource is sized at 500 MW on a nameplate capacity basis. Similar to wind resources, it is important to note that the MISO accredited capacity value for solar is discounted by 50 percent, thus the Strategist model considers generic solar additions in 250 MW firm capacity increments. This

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[8] Reflecting the wind capacity accreditation value for Planning Year 2018/2019.

accredited capacity size increment is comparable to other generic resource assumptions, and thus evaluating solar in this size increment is appropriate.
We derived forecasted solar costs from the publicly available LCOE data in the NREL ATB as well. Similar to the adjustments for wind resources, this cost has been adjusted for tax credit impacts in the relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with greenfield generation facilities, as described further below.

Our modeling also includes a forecast of distributed solar adoption, applied as a supply-side resource with an assumed adoption rate. In addition to these static forecasts, we had planned to include distributed residential and commercial solar as generic resource options in the modeling. However, we ultimately found these resources would not be selected by the model and eliminated them from the optimization exercise. We feel this is justified, as generic distributed solar continues to be significantly more expensive, on a levelized cost of energy (LCOE) basis, than large-scale solar. This cost delta exists even when including transmission costs for large-scale solar, and as a result, it would be highly unlikely that distributed solar would be selected in our scenario optimizations where the model could choose less expensive large scale solar instead. Therefore, to improve model runtimes and reduce truncation issues, as discussed in Chapter 4: Preferred Plan, distributed solar was included at an assumed adoption rate and not further optimized in the Strategist model.

Please see Appendix F1 for more information regarding distributed solar forecasts.

3. Natural Gas

We have included three potential generic resource configurations for natural gas, given the different types of generator and location types. Specifically, we have included options for both CT and CC generic units. Based on our pre-screening review of cost and performance data available from major equipment suppliers and construction contractors, we developed generic resource options based on those we felt had the best economic viability in our system.

For CTs we developed two generic options, differing in size, configuration, and whether the site would be green- or brown-field, based on the available external data noted above and internal engineering assessments. For CCs, we developed one generic option, and applied similar methods to identify appropriate generator cost and performance assumptions from external sources and internal engineering assessments. Here, however, we depended upon an external consultant analysis to better understand potential interconnection costs across several greenfield sites, given increased complexity of siting a several hundred MW gas generation unit and navigating the current MISO generator interconnection process.

4. *Battery Energy Storage*

For the first time in this IRP process, we have developed a generic four-hour battery energy storage resource to include in our Strategist modeling. The unit is sized at 331 MW, which we selected based on both our understanding of our system's future capacity needs and to ensure size parity with one of our generic CT options. Our resource cost assumptions are based on bids our Public Service Company of Colorado operating company received in response to a late 2017 all-source solicitation. To forecast future costs, we applied NREL ATB estimated technology learning curves to these internal cost estimates. For more discussion on storage, see the Minnesota Energy Storage Assessment in Appendix F7.

B. Demand Side Management (DSM)

Based on external studies and stakeholder feedback, we have updated our approach to modeling DSM resources in this Resource Plan, as compared to past years. The Company utilized a *Demand Response Potential Study* provided by the Brattle Group (Appendix G2) and a *Minnesota Energy Efficiency Potential Study*[9] prepared for the Minnesota Department of Commerce, Division of Energy Resources to convert DSM resources into supply-side option "Bundles," which could compete against other resource alternatives in Strategist modeling. Our approach to developing Bundles from the information provided in the study is described below.

1. *Energy Efficiency (EE)*

Based on external studies and internal expertise, the company developed three Bundles, termed Program, Optimal, and Maximum. Internal experts provided detailed cost, and energy and demand avoidance characteristics, for the three Bundles by year. Each Bundle is included in Strategist as a supply-side resource the model could potentially select. The Program and Maximum Bundles are based on the 2018 *Minnesota Energy Efficiency Potential Study* findings. The Optimal Bundle was developed by the Company using the study results for optimal demand reduction (as opposed to energy reduction). Each Bundle included in our resource modeling is incremental to the last, and selection of any Bundle is dependent on the Bundle before it being

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[9] Study available at: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected).

2. *Demand Response (DR)*

Similar to the process for EE, we developed Demand Response (DR) Bundles, so that DR could be treated as a supply-side resource in the Strategist modeling. Consistent with past practice, the Company developed a Base DR Forecast from existing programs, which was included in all baseline resource modeling. The Company then developed three DR Bundles incremental to the Base DR Forecast, based on the Brattle Study noted above. The DR Bundles were designed by taking a point-in-time supply curve of DR options in the study, and developing more detailed annual demand reduction and cost characteristics by year. The Bundles were generally sized to account for supply curve price thresholds, with Bundle 1 achieving demand reduction of 270 to 542 MW; Bundle 2 achieving an incremental 107 to 242 MW; and Bundle 3 achieving an incremental 89 to 112 MW during the planning period. Similar to EE, the DR Bundles are incremental to each other and dependent on the preceding Bundle being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected).

C. *Transmission Costs for Greenfield Resources*

In addition to generating resource assumptions, our Strategist modeling also includes transmission cost considerations for new greenfield resources. These values are intended to capture the transmission expansion and/or interconnection costs required to successfully integrate new greenfield resources into the system. Given current challenges with the MISO interconnection process, and shrinking available transmission capacity on the system, significant study delays and major upgrade costs are likely to result in elevated transmission costs for future resources. Therefore, the Company engaged in a number of internal and external studies in order to appropriately represent anticipated transmission costs associated with new greenfield CT, CC, wind and solar resources. To assess CC transmission delivery costs, the Company hired Excel Engineering, a third party consultant, to perform a study that evaluated potential costs for six different locations on the system. The study identified the potential for high interconnection costs at all of the potential site locations, ranging from a low of $263 million to a high of $1,354 million. Cost levels in this study are dependent in part on the percentage of planned projects that withdraw from the MISO queue. Excel Engineering's Interconnection Cost Estimates is included in Appendix R.

To assess wind and solar transmission delivery costs, the Company's internal Transmission Planning Group performed a random placement technique study. This study identified and solved two benchmark cases to mimic the MISO process. Next, new solar capacity was added at random locations, in order to study the modeled effect on the transmission system. These results were then compared back to the "benchmark" study, to help identify transmission system violations. Finally, interconnection cost estimates were developed by estimating the costs necessary to remedy the violations identified in the study. This methodology is further explained in Appendix F5.

IV. POTENTIAL RESOURCES NOT CONSIDERED IN MODELING

The Company considered several additional technologies in the initial screening process that, in the end, were not included in modeling. We discuss these resources and why they were not included below. We will continue to monitor and screen these options for possible inclusion in future Resource Plans, and/or allow them to compete in future competitive resource acquisition processes, in order to gain additional information on their potential costs and operating characteristics.

A. Biomass

New biomass resources were excluded from consideration as generic options, primarily due to cost. Generic estimates for biomass resources from the U.S. Energy Information Administration (EIA), and other sources, indicate that the capital costs of biomass resources are substantially higher than those associated with generic wind, solar, and natural gas resource options. As a result, the Company did not include a generic biomass resource for consideration in the modeling.

We anticipate, however, that future acquisition processes may allow biomass resources to compete in resource solicitations. There are also existing biomass resources in our region that may be available to help meet our future resource needs. If found to be cost competitive, they could be selected to displace other generic options identified in our Plan.

B. Combined Heat and Power (CHP)

CHP was not included as a generic resource option, as studies indicated it will have limited economic potential during the planning period. The Company engaged the Electric Power Research Institute (EPRI) and ICF International to evaluate the technical and economic potential for CHP applications in our Minnesota service area. The study estimates a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential in Xcel Energy's Minnesota service territory. Under the base scenario, CHP adoption is estimated at 43 MW through 2039. We provide the study as Appendix S.

C. Nuclear

Nuclear is an important, reliable resource that helps contribute to our carbon-free portfolio. There are a number of existing and new nuclear technologies currently being considered for future deployment; however, while these technologies appear promising, there remain commercial barriers to adoption such that we did not include them as generic resource options for our plan. Outstanding commercial uncertainties include:

- Technological maturity and component manufacturing experience
- Risks and costs related to construction delays and/or budget overruns
- Options for disposal of spent nuclear fuel from new facilities
- State and federal regulatory barriers or uncertainty

Of note, Minnesota state statute currently prohibits the Commission from issuing a Certificate of Need for the construction of a new nuclear facility.[10] We further discuss emerging nuclear technologies in Section V below.

D. Pumped Hydro

Pumped hydro is a mature flexible-duration storage technology with a relatively long operational life; however, environmental challenges and resource economics have generally limited its growth. Further, pumped hydro unit configurations and costs are highly site specific, which makes it a difficult resource to represent generically. As a result, the Company did not include a generic pumped hydro resource for consideration in modeling. Similar to biomass resources, the Company remains willing to evaluate pumped hydro projects in future resource solicitations, and if cost effective, pumped hydro resources could displace generic resource options identified in this Plan.

E. Coal

New generic coal resources were eliminated from the list of resource options due to cost, environmental challenges, and non-alignment with our strategic goals. Capital costs for generic coal resources are high relative to new gas and renewable resource options. Low natural gas prices, increased renewable penetration, and regulatory risk

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[10] Laws of Minnesota 1994, Chapter 641, Article 2, Section 1, Subd. 3b.

create additional challenges and major risks for new coal resources. Furthermore, adding coal resources with high carbon emission levels would not align with our commitment to deep carbon reduction on our electric system. For these reasons, we have excluded new coal resources from our modeling. While the Company will continue to monitor carbon capture and sequestration technology developments, we do not expect to consider new coal resources in future resource plans.

V. EMERGING TECHNOLOGIES

As we have previously stated, we can achieve our 2030 carbon reduction goals with existing technologies; however, achieving our vision of a carbon-free electricity supply by 2050 will require significant technology developments that either do not yet exist or are not yet commercialized. In particular, our system will need stable baseload and dispatchable carbon-free generation, and energy storage technologies that can help us maintain reliability for every hour of every day while also keeping our electricity affordable for customers. We are continually assessing new technologies that may be viable options for future resource planning cycles. Below we present a non-exhaustive list of example technologies we are currently tracking.

A. Allam Cycle Application for Emissions Capture in Natural Gas Plants

The Allam Cycle uses natural gas to produce power, but in a different fuel burning process than traditional CTs. Instead of using ambient air for combustion directly, the plants burn natural gas with pure oxygen generated within an Air Separation Unit. This "oxy-combustion" produces CO2, which is then used in the plant's electricity generation process. Using pure oxygen rather than ambient air eliminates nitrogen oxide emissions from the plant's process. The CO_2 released from the combusted natural gas is captured within the plant's process and reused to support additional cycles of fuel combustion. Heat energy is also recovered and used in the process. Excess CO_2 not needed for energy generation can be stored or used in other industrial processes.

NET Power, a company working to commercialize this technology, has recently finished a demonstration project in Texas that is providing power to local customers and undergoing testing to connect to the broader transmission system. They are also working to develop a larger commercial facility with Occidental Petroleum.[11] While this technology remains more expensive than conventional gas plants, we will

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[11] *See* Patel, Sonal. "Insite NET Power: Gas Power Goes Super-critical." Power Mag (April 2019). Available at: https://www.powermag.com/inside-net-power-gas-power-goes-supercritical/

continue to monitor this and other potential developments in carbon capture and storage for potential future application in our system.

B. Hydrogen for Power Generation

Hydrogen is another fuel with potential to support dispatchable carbon-free generation as burning hydrogen, by itself, does not produce any carbon emissions. In existing applications; however, hydrogen is typically mixed with natural gas, which has the effect of lowering a plant's CO_2 emissions levels. Introducing hydrogen into the fuel mix for an existing gas plant does not always require substantial plant retrofits. In fact, some conventional gas turbines are already capable of burning hydrogen in low-to-medium concentrations. For higher concentrations, more significant plant configuration changes are likely required.[12]

There are several methods of producing the hydrogen that would be burned in these units, from using existing industrial process byproduct hydrogen to producing it in dedicated water electrolysis facilities. Current methods like water electrolysis are, in themselves, energy intensive, and as such can make using hydrogen for electricity generation expensive. As the share of variable renewables on the electric grid increases, however, these processes may be able to use inexpensive (or negative priced) excess energy in some hours of the day to reduce the cost of producing the hydrogen. In this sense, hydrogen derived from renewable energy serves as a long duration storage option, where the fuel can be stored over days, weeks or months until needed and burned in a dispatchable plant without any carbon emissions.[13]

Pilot projects in Germany and Denmark, for example, are currently testing using excess wind generation to produce hydrogen through electrolysis[14] that can then be used as needed in a retrofitted natural gas generation plant. Various companies, including leading CT suppliers and startups, are working to further develop and commercialize both the turbines that can run on higher levels of hydrogen and the electrolysis facilities that would produce hydrogen using excess clean energy. We continue to monitor technology progress in the hydrogen space, to evaluate the

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[12] Goldmeer, Dr. Jeffrey. "Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem." General Electric Company (May 2018). Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf

[13] *Id.*

[14] Fairley, Peter. "Europe Stores Electricity in Gas Pipes." Scientific American (April 2019). Available at: https://www.scientificamerican.com/article/europe-stores-electricity-in-gas-pipes/

potential for our gas generation assets to convert to hydrogen use in the future. We are also exploring ways to use electricity generated from our nuclear units to generate hydrogen through on-site electrolysis.

C. Emerging Nuclear Technologies

Nuclear power is one of the most reliable and lowest operating cost resources we have in our system. Our two nuclear plants provide nearly 30 percent of our electricity mix, carbon-free and at a cost (fuel and O&M) below $30/MWh. However, it is increasingly difficult to build new conventional nuclear units, in part due to their typical scale and associated high upfront costs.

Substantial industry research into several advanced nuclear technologies is ongoing. For example, in recent years there have been renewed efforts to develop advanced reactors that use sodium, gas or liquid metals in place of traditional cooling materials. Renewed research is also ongoing into applications wherein the nuclear fuel itself can be dissolved into molten salt, in order to operate at lower pressures than traditional pressurized water reactors. Using molten salt in this way is intended to improve safety considerations. Some advanced reactor designs are intended to reduce spent fuel volumes, by either enabling longer durations between refueling events or instituting closed fuel cycles that reprocess and reuse spent fuel within the reactor. Reducing spent fuel volumes can both reduce fuel costs and mitigate spent fuel storage challenges. Some designs also incorporate passive safety designs through natural convection cooling.

Other developers are researching potential application of light water reactor technology to small modular reactors (SMR). SMRs would be intended to be more flexible, able to serve smaller scale needs, and allow reduced backup infrastructure, as compared to existing nuclear units. This general concept is already used in military applications and for marine vessels that need to go long periods between refueling. SMRs are typically less than 300 MW in size and factory fabricated in modular units. The modular design is intended to enable streamlined production, shipping, and installation processes, in order to help manage costs. Further, the units are intended to go longer in between refueling outages than conventional plants, and allow refueling of one unit as the others continue to operate.[15] As an emerging technology, however, it is not yet clear whether SMR costs will be competitive with other sources of energy.

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[15] *See* "Benefits." NuScale Power. Available at: https://www.nuscalepower.com/benefits

Several companies are currently working through NRC licensing processes for emerging nuclear technology, with the goal of attaining design approval for their advanced and small modular reactors by the mid-2020s, in order to complete pilot plants in the late 2020s.

D. Energy Storage Advancements

Large scale battery energy storage is increasing its presence on the grid, being used to integrate renewables, defer grid investments, and more. In fact, the Company has had a sodium-sulfur battery operating on the NSP System since 2009, in order to gain valuable technology experience.[16] Many batteries installed today use lithium-ion (li-ion) chemistries, benefitting from economies of scale gained in consumer electronics and, to some extent, electric vehicle manufacturing. Grid-scale li-ion batteries typically store energy for relatively short durations, providing a few hours of capacity or energy services.[17] While these shorter duration batteries hold great promise to mitigate demand peaks or short periods of intermittency now, in the long term with higher renewable penetration, the grid will need a combination of short and longer duration storage capabilities to effectively match variable renewable output to customer load. Further, costs for short and longer duration storage will need to decline further for energy storage to be deployed at scale.

To this end, there are several emerging storage applications that either use different chemical and physical properties, with the goal of mitigating cost and/or duration challenges. A few examples of emerging energy storage technologies we follow include:

- **Solid state li-ion batteries**: Current li-ion batteries, while continuing to become more cost effective for stationary storage applications, use a liquid electrolyte that has room to improve in terms of energy density. Development is underway that would replace the liquid electrolyte with solid materials, that offer higher energy densities and reduce potential for leakage and flammability. Solid state batteries hold promise to reduce the cost of energy storage, because increasing energy density allows more energy to be stored for discharge when needed. They also hold promise in increasing the number of times the battery can cycle before requiring material replacement.[18] These batteries are not yet

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[16] The Luverne MinnWind Storage Project is a 1 MW, 7MW-h sodium sulfur (NaS) battery paired with an 11 MW wind facility in western Minnesota.

[17] As noted above, our modeling included a 4-hour duration generic battery energy storage option, which we believe is in line with most commercialized grid-scale lithium ion batteries installed currently.

[18] Tohoku University. "Highest energy density all-solid-state batteries now possible." ScienceDaily. (March

commercially available, but there is substantial interest in continuing development. Large industrials – such as Samsung, Hyundai, and Solvay – and venture funds such as Breakthrough Energy have invested in startups developing the technology.[19]

- **Flow batteries**: Flow batteries are a category of technology that includes several types of chemistry compositions. While not a new technology in general, application to stationary power system remains relatively nascent. In general, flow batteries are a cross between a conventional battery and a fuel cell, where a liquid electrolyte cycles through a core, and ion transfers between the cathode and anode generates electricity. As such, flow batteries tend to have favorable life cycles and may provide longer duration storage than li-ion designs; as the electrolytes are separate from the cell itself, the tanks can be scaled up without also scaling up the cell. However, round trip efficiency can be lower than in lithium-ion batteries, and this application has not been proven to serve substantially longer durations than lithium-ion.[20] [21] San Diego Gas & Electric, a utility in California, has recently installed a flow battery to its grid for a four year pilot project, where it will evaluate battery economics, renewable integration, and wholesale market services potential.[22]

- **Electrothermal energy storage**: Thermal storage for renewables has been implemented in limited use cases. There are, for example, existing large scale solar thermal facilities in the desert southwest that use large tanks of molten to store energy in the form of heat, across several hours or even days, until needed. This concept has not traditionally been applied to solar PV or wind facilities; however, a company called Malta is working to develop Carnot batteries (i.e. pumped thermal storage) that could be deployed either at greenfield or brownfield locations. Their concept converts the electricity from a solar PV or wind facility into thermal energy through a heat pump. Heat can be stored in molten salt while cold is stored in a chilled liquid. To discharge the energy, transfer fluid is run through both the hot and cold storage tanks, creating steam that can be used to convert the energy back into electricity. This

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2019). Available at https://www.sciencedaily.com/releases/2019/03/190322105701.htm

[19] Wesoff, Eric, "Industry Giants Samsung and Hyundai Invest in Solid-State Batteries." Greentech Media (September 2018). Available at: https://www.greentechmedia.com/articles/read/industry-giants-samsung-and-hyundai-invest-in-solid-state-batteries

[20] Dagget, Jamie. "Can Flow Batteries compete with Li-ion?" DNV GL (January 2019). Available at: https://blogs.dnvgl.com/energy/can-flow-batteries-compete-with-li-ion

[21] "Flow Batteries." Energy Storage Association. Available at: http://energystorage.org/energy-storage/storage-technology-comparisons/flow-batteries

[22] "California ISO Adds Flow Battery to the Grid." T&D World (May 2019). Available at: https://www.tdworld.com/energy-storage/california-iso-adds-flow-battery-grid

system is intended to provide longer duration storage, with a longer facility life and at lower capital cost than a typical battery storage facility.[23] In Germany, Malta and other partners are working to develop a pilot project on a brownfield coal site, in order to repurpose the steam turbine to generate electricity from the stored renewable energy.[24]

- **Subsurface pumped hydro storage**: Pumped hydro storage has been the primary method of long duration storage on the grid for many years, including the Company's own Cabin Creek pumped hydro facility in the Colorado service area. As noted above, however, we have not included it in our generic resource modeling due to dependence on specific geologic structures and related challenges in estimating generic costs. There are, however, companies working to provide scalable pumped hydro solutions that can be built in areas without the typical geologic structures. For example, a company called Quidnet is proposing to use conventional reservoir technology and typical oil and gas well practices to create subterranean compressed hydro storage facilities. To store energy, water would be pumped down into an underground well and held under pressure in the rock formation. When energy is needed, the pressure would be released and the water would flow through a conventional hydro turbine to generate electricity. This system is intended to be closed loop, to conserve water. The necessary underground rock structures are also more ubiquitous, and the plants can be more flexible in scale than conventional pumped hydro storage.[25]

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[23] "Projects: Malta." Google X. Available at: https://x.company/projects/malta/

[24] Deign, Jason. "Germany Looks to Put Thermal Storage Into Coal Plants." Greentech Media (March 2019). Available at: https://www.greentechmedia.com/articles/read/germany-thermal-storage-into-coal-plants

[25] "Solution." Quidnet Energy. Available at: http://www.quidnetenergy.com/