



Project Tundra: A Step in the Wrong Direction

Carbon Capture Project Carries Large Risks for Investors and Co-op Members

Executive Summary

Square Butte Electric Cooperative and Minnkota Power Cooperative own and operate Unit 2 at the Milton R. Young (Young Unit 2) coal-fired plant in Center, N.D. The cooperatives are proposing to retrofit the 43-year-old, 455 megawatt-capacity unit with equipment to capture 90% of its carbon dioxide (CO₂) emissions and either sequester the CO₂ underground or sell it for use in enhanced oil recovery (EOR) activities.

The proposal, dubbed the Tundra Project by its supporters, received \$16.9 million this spring from the U.S. Department of Energy (DOE) to complete the permitting work needed for two underground injection wells and then build them. Last fall, the project was awarded \$9.8 million in DOE funds to complete a front end engineering and design (FEED) study for the project, with the goal of developing “design, costing and performance data needed to commence project financing activity,” as well as a final project schedule.

In short, this DOE money is being used to start the project, instead of evaluating whether the project is viable in the first place. This is critical, as Minnkota has pledged it will not pursue Project Tundra if it “substantially increases electric rates.”¹

IEEFA’s analysis of the project shows it faces significant risks and uncertainties that could undermine its economic viability and lead to higher electric rates for the ratepayers of the cooperatives that buy power from Minnkota or Minnesota Power. These include:

- Uncertainty over the cost of adding the new carbon capture facility and associated project infrastructure;
- The potential that significant problems will be experienced during the scaling up of the planned Fluor capture technology from its small tested size (5 megawatts to 40 megawatts) to a commercial-scale 455MW coal plant;
- Uncertainty whether the project will capture enough CO₂ so that it can be financed entirely thru federal 45Q tax credits. If not, Minnkota would be forced to borrow additional funds to build and, perhaps, operate the project,

¹ Project Tundra website.

thereby incurring unexpected costs that will be borne by ratepayers, not investors;

- Uncertainty over the cost of capturing the CO₂ produced by the plant;
- Uncertainty over the cost of sequestering captured CO₂;
- Young Unit 2 is not a low-cost generator and it is quite possible, if not likely, that the cost of the electricity from the plant will be substantially higher if it is retrofitted for carbon capture. Ratepayers already are paying far more for electricity from the plant than they would if their co-ops purchased the same amount of power from competitive wholesale markets. This can be expected to get worse in future years, especially if Project Tundra is undertaken; and
- Uncertainty whether there will be a viable market for using the captured CO₂ for EOR activities.

Minnkota has acknowledged that carbon capture, utilization and storage technology has not been adequately demonstrated for nationwide use.² However, it is gambling that Project Tundra can succeed because of its “unique geographical location.”³ If it loses this bet, the ratepayers of the 11 cooperatives that own Minnkota and Square Butte may have to pay substantially higher rates for power from Young Unit 2, or indeed, for a failed project.

Square Butte and Minnkota Power would be well-served by taking the time afforded by the DOE grants to weigh the risks carefully—going forward risks putting their co-op customers on the hook for significant construction cost overruns and long-term responsibility for higher operations and maintenance costs. A better option would be to follow the lead of Great River Energy which earlier this year announced plans to retire the younger, larger and better running Coal Creek station, close Young Unit 2, and embrace the renewable energy transition by building cleaner, lower-cost wind with storage to meet its capacity needs.

² Minnkota Power Cooperative. [In the Matter of Minnkota Power Cooperative Inc.’s 2019 Resource Plan](#). June 28, 2019, p. 39.

³ *Ibid.*

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Risk No. 1: Uncertainty Over the Cost of Adding the Carbon Capture Facility and Associated Project Infrastructure

Minnkota has offered a range of different estimates for the capital cost of retrofitting Young Unit 2 for carbon capture. First, early in 2019, Minnkota submitted its 2019 integrated resource plan (IRP) to the Minnesota Public Utilities Commission that projected that Project Tundra, the official name for the carbon capture retrofit initiative, would cost between \$1.3 billion and \$1.6 billion (with associated EOR infrastructure, where appropriate).⁴ However, the Project Tundra website presents a much lower \$1 billion cost for the project.⁵

It is vital to put those estimates in context, and doing so shows that Minnkota's numbers are unreasonably optimistic. The capital cost of building the 240MW Petra Nova facility was \$1 billion, or \$4,166 per kilowatt (kW), in a mix of 2014 to 2016 dollars.⁶ This converts to a cost of nearly \$5,000 per kW in 2026 dollars. Minnkota's apparent range for the cost of retrofitting Young Unit 2 with CO₂ capture is between 33% and 58% lower, on a per-kilowatt basis than Petra Nova's actual cost, adjusted to 2026 dollars.

The theory underlying the development of new technologies, such as carbon capture at commercial-scale power plants, is that over time, lessons learned from the construction and operation of new plants will drive down the prices for building and running each successive unit. For example, the cost of installing new utility-scale solar capacity declined by nearly 70% between 2010 and 2018 as a result of the lessons

Project Participants and Background

Square Butte Electric Cooperative (Square Butte) owns Unit 2 at the Milton R. Young Station (Young Unit 2), a 455 megawatt, mine-mouth generating station located near Center, N.D.. Young Unit 2 burns lignite. It began commercial operation on May 6, 1977.

Both Square Butte and Minnkota Power Cooperative (Minnkota) are owned by the same 11 member-owned electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota operates Young Unit 2 for Square Butte.

Currently, Minnkota and Minnesota Power Company each purchase 50% of the generation from Young Unit 2 from Square Butte. Minnkota also purchases 28% of Minnesota Power's share of the generation under a separate agreement.

Minnkota says the Tundra Project would add equipment to capture 90% or more of the carbon dioxide (CO₂) produced at Young Unit 2 and then either sequester the captured CO₂ in an underground geological formation or use it for enhanced oil recovery (EOR).

The plan is to fund the retrofit work by using the federal government's recently expanded 45Q carbon capture tax credit program. Each metric ton of CO₂ that is sequestered is eligible for a \$50 federal tax credit. Each metric ton that is used for EOR is eligible for a \$35 federal tax credit.

Minnkota is not eligible to use the federal tax credits. Therefore, it will have to find a partner or outside investor that will be able and willing to fund the capital cost of retrofitting Young Unit 2 for carbon capture.

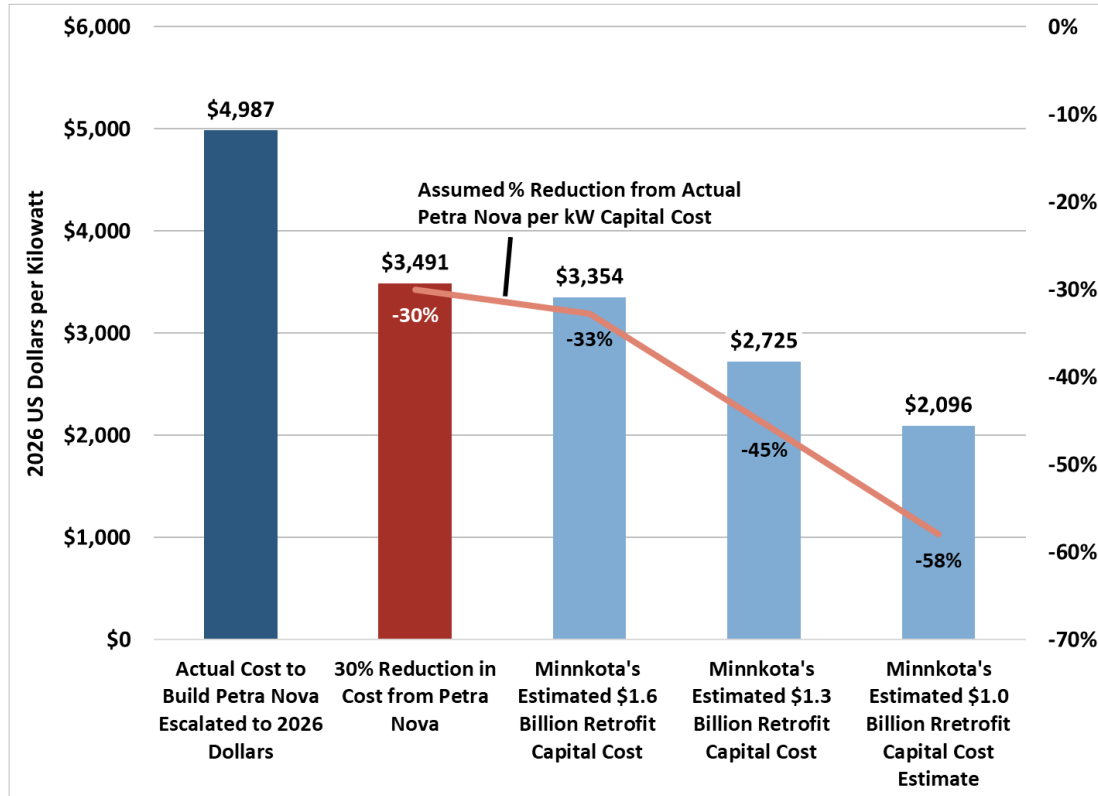
⁴ *Ibid*, p. 40.

⁵ Project Tundra website.

⁶ EIA. Petra Nova is one of two carbon capture and sequestration power plants in the world. October 31, 2017.

learned in the building and installation of 24.7 gigawatts (GW) of new solar capacity.⁷ Similarly, the price of installing new wind capacity fell by 40% between 2009-2010 and 2018 as a result of the lessons learned during the installation of 56GW of new wind capacity.⁸

Figure 1: Actual Petra Nova Capital Cost vs. Minnkota Estimated Range of Retrofit Costs for Milton R. Young Unit 2



Source: EIA, *Lignite council to push for carbon-capture project this year.*

However, carbon capture technology is not like solar and wind technology. The decline in solar and wind prices was driven by significant research and development investment, robust competition among suppliers and thousands of new commercial projects. By contrast, there are only two carbon capture projects at coal-fired power plants in the entire world—Petra Nova and Boundary Dam 3 in Saskatchewan. Unlike with solar and wind, few carbon capture initiatives are in play, meaning costs for the next projects are unlikely to decline significantly.

Moreover, instead of assuming that the cost of retrofitting new carbon capture technology to existing coal-fired generators would decline over time, Minnkota is assuming that the cost of retrofitting Young Unit 2 with CO₂ capture—making it the very next (or at most, one of the very next) commercial-scale power plants in the

⁷ LBNL. *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States*, 2019 Edition. December 2019.

⁸ U.S. Department of Energy. *2018 Wind Technologies Market Report*. August 2019.

U.S. to be retrofitted with carbon capture technology—would immediately be 33% to 58% lower (on a dollar per kW basis) than the cost of building the Petra Nova plant in Texas.

Another factor undercutting Minnkota's optimistic project cost estimates is that it will not be using the same Mitsubishi-based technology used at Petra Nova. Instead, the capture technology planned for Project Tundra was developed by Fluor and has never been operated at commercial scale capturing CO₂ from power plants. In fact, the only experience for the Fluor technology is capturing the CO₂ from a 40MW slipstream of a gas-fired combustion turbine from 1991 to 2005 and capturing the CO₂ from a 5.5MW slipstream at the 757MW Wilhelmshaven coal plant in Germany.^{9,10} Consequently, Project Tundra will involve a significant scaling-up of the technology, and the plant will be the first commercial-scale application of the Fluor capture technology at an operating coal-fired generator.

In other words, the Young retrofit will be a first-of-a-kind project unlikely to benefit significantly from the development experience at Petra Nova. But that is exactly what Minnkota is assuming: That it will be able to complete a 10- to 100-fold scale-up of Fluor's CO₂ capture technology for substantially less than it cost to build Petra Nova. That does not seem realistic.

Other estimates for CO₂ retrofits suggest that the cost of adding carbon capture will be substantially higher than Minnkota has cited. For example, NRG, has said that it could build a second Petra Nova for 80% to 90% of the cost of the first one, suggesting a savings of only 10% to 20%.¹¹

The International Energy Agency, an advocate for carbon capture, has estimated that the next generation of power plant carbon capture projects (that is, those after Petra Nova) will achieve 25 to 30 percent reductions in both capital and operating costs.¹² The National Association of Regulatory Utility Commissioners (NARUC) has noted that the IEA's projected reductions in the next generation of power plant CCS projects, "... support the idea that costs will come down with more facilities."¹³

It is possible that the cost of retrofitting Young Unit 2 with CO₂ capture will achieve some cost savings from (1) lessons learned at Petra Nova, (2) the reuse of facilities at the plant and (3) some economies of scale. However, it also is quite possible that unanticipated problems will occur in scaling up the CO₂ capture technology from the small facilities where its feasibility has been tested.

Such technology scale-up activities almost always lead to unanticipated problems and additional costs, both during construction and operation. For example, the

⁹ U.S. Department of Energy. [Carbon Capture Opportunities for Natural Gas Fired Power Systems](#). January 2017.

¹⁰ U.S. National Energy Technology Laboratory. [Carbon Capture and Storage Database](#).

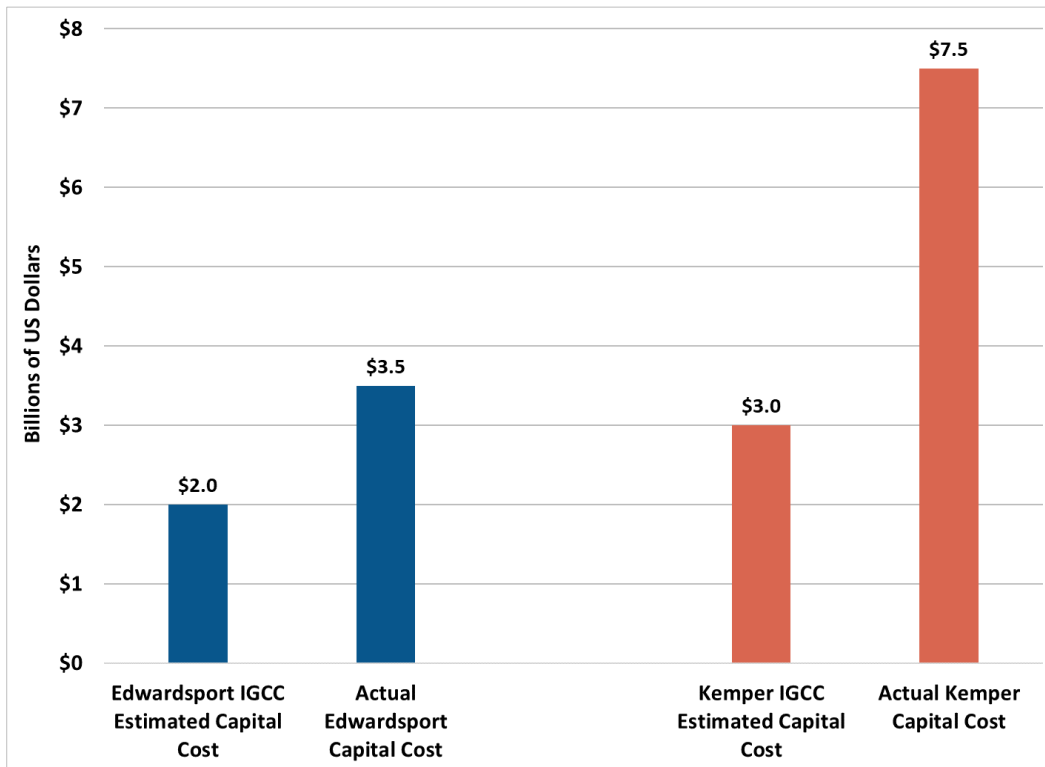
¹¹ E&E News. [Carbon Capture takes 'huge step' with first U.S. plant](#). January 10, 2017. Also: New York Times. [Can Carbon Capture Technology Prosper Under Trump](#). January 2, 2017.

¹² National Association of Regulatory Utility Commissioners (NARUC). [Carbon Capture, Utilization, and Storage: Technology and Policy Status and Opportunities](#). November 2018, p. 47.

¹³ *Ibid.*

actual capital costs of both the Edwardsport and the Kemper integrated gasification combined cycle plants were both substantially higher than the owners of either plant had estimated when they obtained permits from their states to undertake the projects. Both projects involved the scaling-up of smaller test facilities to commercial-scale power plants.

Figure 2: Actual vs. Estimated Costs of Edwardsport and Kemper IGCC Plants



The construction of first-of-a-kind, commercial-scale nuclear plants with new technologies also has run into significant cost overruns. For example, the estimated capital cost of Georgia Power Company's 45% share of the Vogtle 3&4 nuclear plants has more than doubled from about \$4.5 billion to more than \$9.6 billion, and the project remains a year or more from completion.¹⁴

For these reasons, the \$1 billion low end of Minnkota's estimated range of capital costs does not appear to be realistic. Even the \$1.3 billion midpoint and \$1.6 billion estimates are extremely optimistic. The actual cost of retrofitting Young Unit 2 for CO₂ capture could easily exceed the \$1.6 billion high end of Minnkota's range.

¹⁴ Georgia Public Service Commission. [Document Filing #180800](#). April 20, 2020.

Risk No. 2: Uncertainty About How Much CO₂ Will Be Captured by Project Tundra

The federal 45Q tax credit program is straightforward: The more CO₂ produced and then either stored or reused via EOR, the more money earned. In other words, the total number of credits that a company earns is a function of how much CO₂ it produces and how much of the CO₂ it produces is captured. The program currently allows a plant owner to earn tax credits for the first 12 years after the retrofit goes into service.

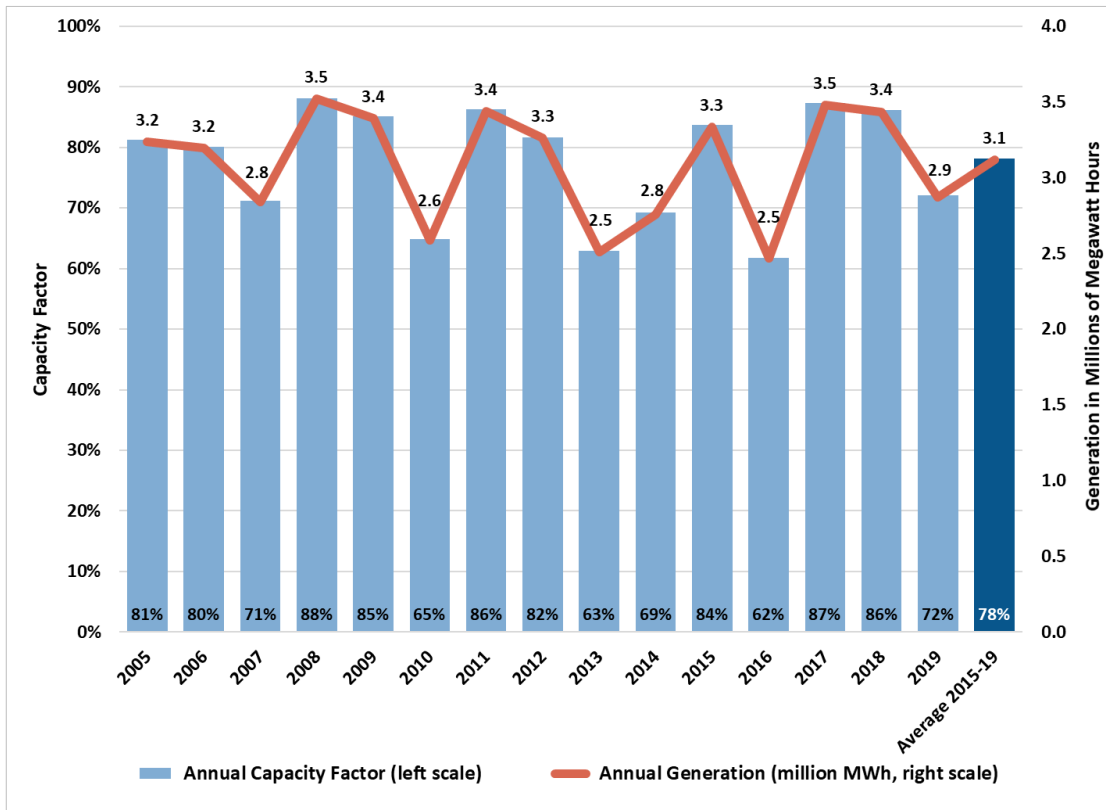
The first variable—the amount of CO₂ the plant produces—is largely dependent on how much the plant operates. The term “capacity factor” indicates how much power a plant produces in a given period versus how much it would have generated if it had operated at 100% power for the entire period. The higher the capacity factor, the more power is generated by the plant. Conversely, the lower the capacity factor, the lower the amount of power generated by the plant. Similarly, the amount of CO₂ produced by a coal plant goes up as its capacity factor goes up.

The Operating History of Milton R. Young Unit 2

The first key to the economics of any carbon capture retrofit proposal is the assumption for the retrofitted unit’s annual capacity factor following after the project’s start-up, particularly for the first 12 years when the tax credits are available.

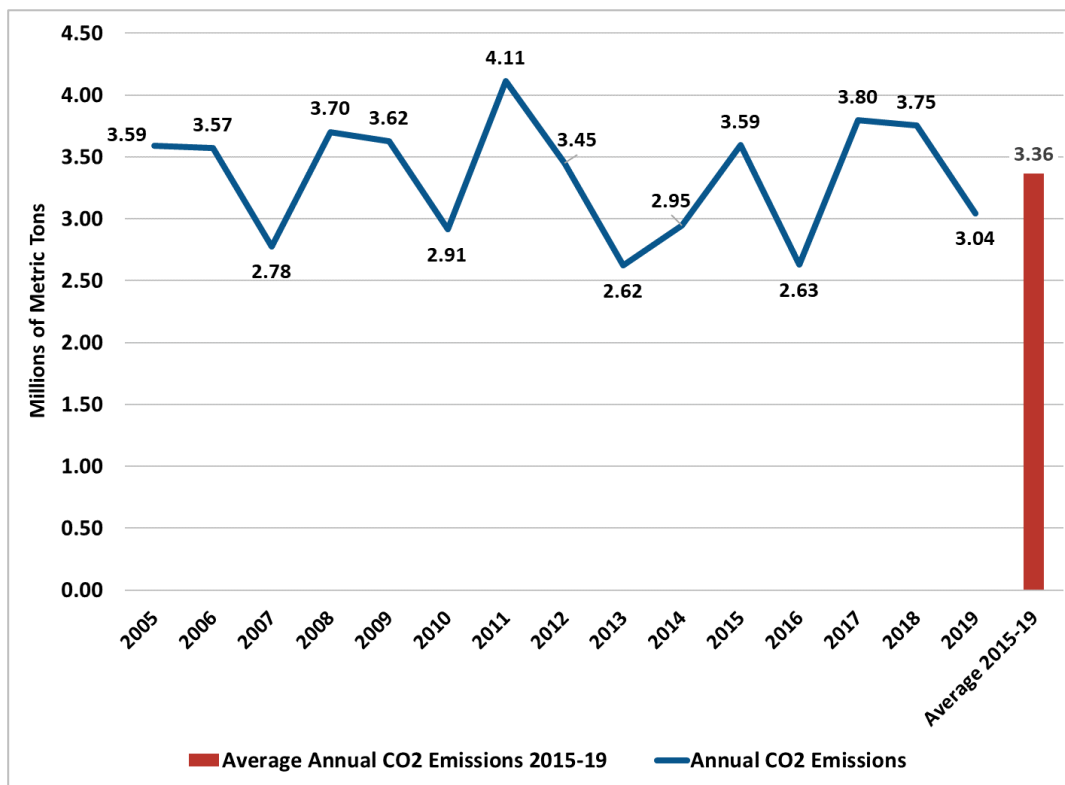
Young Unit 2’s annual generation and capacity factors have varied significantly since 2005, with an annual average generation of 3.12 million megawatt-hours (MWh) between 2015 and 2019. This meant that the unit achieved an average 78% capacity factor during the five-year period.

Figure 3: Milton R. Young Unit 2 Annual Capacity Factors in the Years 2005-2019



Source: EIA Form 923, S&P Global Market Intelligence.

Unit 2’s annual CO₂ emissions fluctuated, along with its annual generation. The unit has emitted an average of 3.36 million metric tons of CO₂ annually since 2015.

Figure 4: Milton R. Young Unit 2 Annual CO₂ Emissions, 2005-19

Source: EPA Continuous Emissions Monitoring Systems data, S&P Global Market Intelligence.

However, a number of factors suggest that Young Unit 2's annual generation (and annual CO₂ emissions) will fall in the years ahead.

Problems Associated With Operating a First-of-a-Kind Project

As noted earlier, the Fluor carbon technology that Minnkota proposes to use at Young Unit 2 has not been operated at commercial scale. Consequently, if Young Unit 2 ultimately is retrofitted with this technology, it will be a first-of-a-kind at commercial-scale project. Industry experience shows that power plants with new and untested at commercial-scale technologies typically have unanticipated operating problems during their initial years of operation, if not longer.

Minnkota's retrofit of Young Unit 2 would be almost twice the size of Petra Nova and four times the size of Boundary Dam 3. As the industry has learned through painful experience, serious and expensive problems can occur when scaling up new technologies.

For example, the Edwardsport IGCC plant has experienced a series of significant operational problems since it entered commercial service in June 2013. As a result, Edwardsport's actual capacity factor on gasified coal (also called syngas) through May 2020 was 48%, dramatically lower than the approximate 80% percent capacity factor on syngas that had been predicted by Duke Energy Indiana for the plant's first

seven years of operations when it was seeking a permit to build the plant.¹⁵ Edwardsport's capacity factor on all fuels (natural gas plus gasified coal) through May 2020 was only 60%.¹⁶

Similarly, Southern Company promoted the use of its TRIG (transport integrated gasification) technology to gasify coal at the Kemper IGCC plant. However, severe problems occurred with the plant's scaled-up gasification technology during pre-operational testing. As a result, the plan to burn gasified coal was scrapped and Kemper (since renamed Plant Ratcliffe) now is the world's most expensive natural gas-fired combined cycle power plant.

Until recently, Petra Nova's owners had not released any information about its operating performance and the reasons for its failure to capture as much CO₂ as planned. However, a March 2020 report by NRG, owner of 50% of Petra Nova, revealed that the project had experienced significant performance problems during its first three years of operations, from January 2017 to December 2019. Data provided in this report shows that Petra Nova's actual capacity factor for the three-year period was just 66%, substantially below NRG's 85% target performance.¹⁷ The project's capacity factor this year, and perhaps in coming years, will be even lower, as it was indefinitely mothballed on May 1 due to low oil prices.

Boundary Dam 3 also has captured much less CO₂ than its owner, SaskPower, predicted when the plant was retrofitted for carbon capture. For example, SaskPower has said that the carbon capture facility at the plant worked only about 40% of the time in much of 2014 and 2015 with the facility being shut down for a nearly two-month maintenance outage in the fall of 2015.¹⁸ The facility also was shut down for 96 days in 2017 to complete projects designed to improve operational performance and reliability.¹⁹ In fact, Boundary Dam had actually captured CO₂ at its maximum daily rate of 3,200 tonnes for just three days in its first 40 months after being retrofitted for carbon capture. Although Boundary Dam 3's performance has improved in recent years, it is still nowhere near the expected level.

The Impact of Plant Aging

Young Unit 2 began commercial operation in April 1977; the unit will be 48 years old by the time the retrofit is scheduled to enter commercial service at the end of 2025. By 2037 (the end of the 12-year eligibility period for the 45Q tax credits), the plant will be more than 60 years old.

This is important because older plants, on average, tend to cost more to operate and maintain and are less reliable, according to analyses by the U.S. Department of

¹⁵ Data from EIA Form 923 and Monthly Reports to the Indiana Utility Regulatory Commission.

¹⁶ Edwardsport's capacity factors in recent years have been a bit better. Its capacity factor on syngas since January 2016 has been slightly above 50% while its capacity factor on all fuels (natural gas + syngas) has been 70%.

¹⁷ U.S. Department of Energy. [W.A. Parish Post-Combustion CO₂ Capture and Sequestration Demonstration Project Final Technical Report](#). March 31, 2020, p. 41.

¹⁸ *SaskPower's 2015-2016 Annual Report*, p. 59.

¹⁹ *SaskPower's 2017-2018 Annual Report*, p. 36.

Energy's Argonne National Laboratory and the National Energy Technology Laboratory, which have found that coal plant heat rates increase with plant age, while plant availability declines.²⁰ Heat rate is a measure of a power plant's efficiency in generating electricity; a higher heat rate means that a plant is less efficient. And, in general, power plants tend to become less efficient as they age. Plant availability measures the percentage of operating hours in which a plant was actually available to generate power. Plants also tend to become less available to generate power as they age, in part because they have more unanticipated problems and unplanned outages.

90% Carbon Capture Has Not Been Proven Over an Extended Number of Years

Proponents of carbon capture, including Minnkota, claim without any supporting operational evidence that the technology has been proven and that proposed projects will be able to capture 90% of a plant's CO₂ emissions day in and day out over a 12-year period.²¹ These claims bear little relationship to the performance to date at Petra Nova and Boundary Dam, the only two coal-fired carbon capture power plants in the world.

Petra Nova

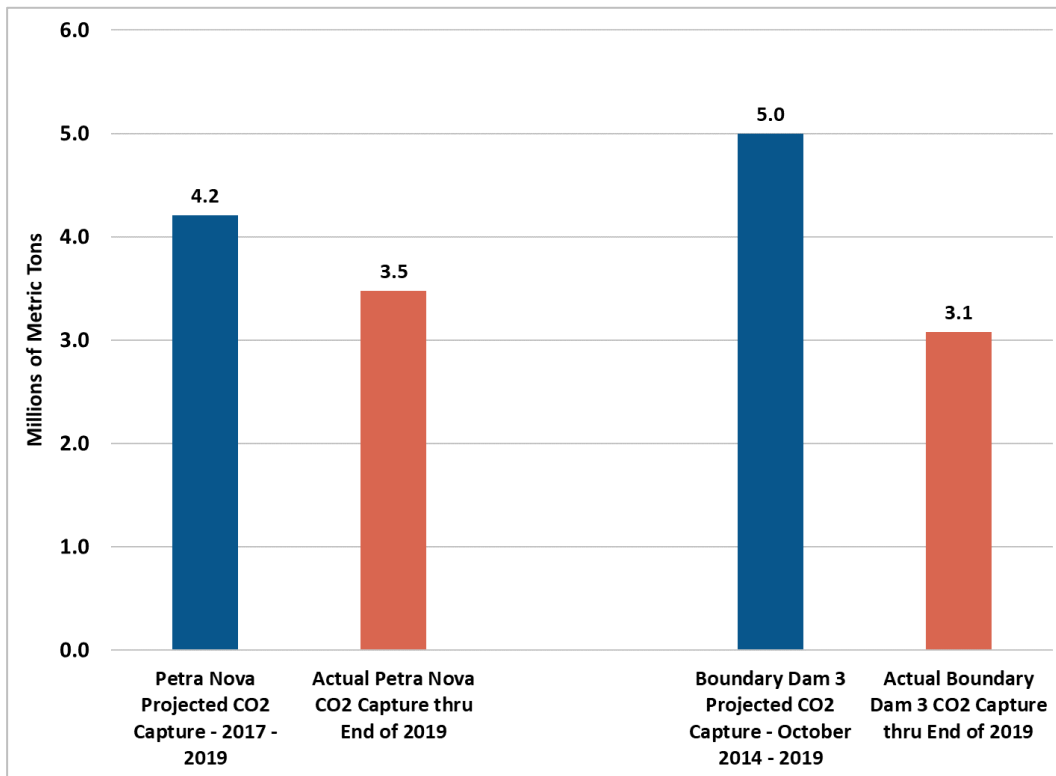
Petra Nova was originally designed to capture "at least 90% of the CO₂ from the flue gas in a 240MW slipstream from Parish Unit 8. Put another way, Petra Nova was expected to capture an average of 1.4 million metric tons (1.54 million short U.S. tons) each year, on average, or about 33% of the total annual emissions from Unit 8.²² Boundary Dam 3 captures the CO₂ from a 110MW plant. SaskPower projected that the plant would capture 1 million metric tons each year. However, both plants failed to achieve these goals, in large part because of operating problems referenced earlier.

²⁰ U.S. Department of Energy. [Staff Report to the Secretary on Electricity Markets and Reliability](#). August 2017, p. 155.

²¹ For example, the Los Alamos National Laboratory [Preliminary Assessment of Post-combustion Capture of Carbon Dioxide At The San Juan Generating Station](#) simply observed that Petra Nova has stated publicly that the facility achieves 90% capture of the processed fuel gas without seeing any actual operational data supporting this claim. December 2019, pp. 9-11.

²² U.S. Department of Energy. [W.A. Parish Post-Combustion CO₂ Capture and Sequestration Project, Final Public Design Report](#). February 17, 2017. Also: EIA. [Petra Nova is one of two carbon capture and sequestration power plants in the world](#). October 31, 2017. Also: U.S. Department of Energy. [W.A. Parish Post-Combustion CO₂ Capture and Sequestration Project Summary](#). September 2012.

Figure 5: Actual vs. Target Amounts of CO₂ Captured at Petra Nova and Boundary Dam 3



Sources: NRG Inc. and SaskPower BD3 Status Updates.

Petra Nova captured 662,000 fewer metric tons of CO₂ during its first three years of operation than projected—despite the fact that Parish Unit 8 actually generated more power and, almost certainly produced more CO₂, than in previous years.²³ And Boundary Dam 3 didn't achieve its goal of capturing 3 million metric tons of CO₂ until early November 2019, after the project had been in operation for five years or two years later than forecasted.

Based on information in NRG's March 2020 Petra Nova report to the Department of Energy, it is clear that the project's actual CO₂ capture rate was in the range of 75% to 83%, not 90% (although it probably did achieve 90% capture on an intermittent basis).²⁴ But that does not establish that carbon capture has been "proven" or "demonstrated" over the long term.

This 75% to 83% range for Petra Nova's capture rate also does not reflect the CO₂ emissions from the combustion turbine that provides the power needed to run the

²³ Parish Unit 8's annual capacity factor rose from 68% in the two years prior to the start of operations at Petra Nova to 72% in the three-year period 2017-2019 after Petra Nova began capturing CO₂.

²⁴ U.S. Department of Energy. [Petra Nova Post-Combustion CO₂ Capture and Sequestration Demonstration Project, Final Scientific/Technical Report](#). March 31, 2020, p. 47.

project's carbon capture systems. When those are included, Petra Nova's net CO₂ capture rate drops to somewhere in the range of 70% or lower.

Data published by SaskPower suggests that Boundary Dam 3's average capture rate in the five-year-plus period between October 2014 and December 2019 fell somewhere around 55% to 60%.²⁵

Risk No. 3: Whether Minnkota Will Be Able To Finance Project Tundra Entirely With Federal 45Q Tax Credits

The presumption in Minnkota's discussions surrounding the proposed carbon capture retrofit of Young Unit 2 is that, in essence, it will be cost-free to the ratepayers of its member-owner cooperatives. The basis behind this presumption is that recently expanded 45Q tax credits will cover the project costs. IEEFA believes this is far from the case, and believes ratepayers and customers will end up paying for significant portions of the project's overall cost.

The theory behind tax equity financing is straightforward: A party with access to a tax credit agrees to sell it to another party to pay for the asset that generated the credit in the first place. As the Congressional Research Service phrased it in a recent report:

*"The term tax equity investment describes transactions that pair the tax credits or other tax benefits generated by a qualifying physical investment with the capital financing associated with that investment. These transactions involve one party agreeing to assign the rights to claim the tax credits to another party in exchange for an equity investment (i.e., cash financing)."*²⁶

So in other words, Minnkota is planning to sell the tax credits from capturing carbon at Young Unit 2 and then store it underground or sell it for EOR activities to an investor who can use the credits as they are earned over the next 12 years or longer. In return, the investor provides upfront funding for Minnkota to pay for the project's construction.

It sounds simple, but there are other factors to consider. For starters, a dollar today is worth more than one earned next year or in the future, so the future tax credits will be discounted. In addition, there is a limited pool of tax equity financing, and developers of newer or less-conventional technologies (such as Minnkota's first-of-a-kind project) will have to pay a risk premium compared to developers of more commercially common projects backed by wind and solar developers.

David Posner explained this part of the puzzle in testimony to the New Mexico

²⁵ SaskPower BD3 Status Update. December 2019.

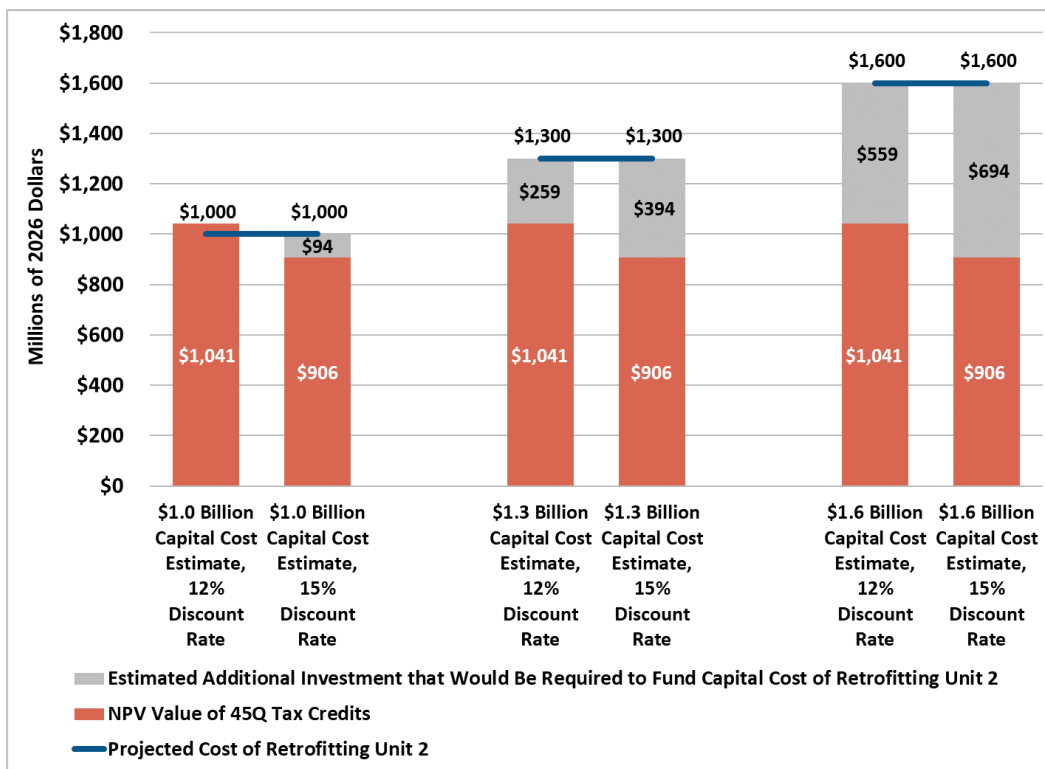
²⁶ Congressional Research Service. *Tax Equity Financing: An Introduction and Policy Considerations*. April 17, 2019, p. 1.

Public Regulation Commission:

“Finally, it is worth noting that tax equity supply is limited and tends to seek the safest investment available ... With wind and solar deals still offering tax credits for projects that will enter service until the statutory deadline for 45Q projects to begin construction, solar deals offering tax credits after that deadline, and both wind and solar projects offering significant accelerated depreciation benefits before and after that deadline, it is likely that tax equity investors will completely shun highly risky CCS projects and choose to limit investments to mature and reliable renewable projects.”²⁷

This means the funding available to Minnkota for the project will be discounted, with the net present value significantly below any realistic estimate of the project’s actual cost, as can be seen in Figure 6 below.

Figure 6: Expected Value of 45Q Tax Credits vs. Projected Cost of Retrofitting Young Unit 2



Source: IEEFA analysis.

As shown, the 45Q tax credits that can be expected by capturing and sequestering or using the CO₂ from Young Unit 2 would only fully cover the entire cost of retrofitting the unit in the unlikely circumstance that the capital cost of the retrofit is just \$1 billion and the co-op’s partners or investors only apply a 12% discount rate in their

²⁷ New Mexico Public Regulation Commission. [Prepared Rebuttal Testimony of David B. Posner on Behalf of Sierra Club](#). November 15, 2019, pp. 3-4.

evaluation of the risk of investing in the project. Even then, there is no reason to expect that the 45Q credits would cover shortfalls in the unit's operating and maintenance costs.

A more realistic estimate is that the net present value of the tax credits at the Young retrofit is likely somewhere between 57% and 80% of the project's costs. Under these circumstances, some other party—Square Butte, Minnkota, the 11 member cooperatives that are its owners, or another partner or investor—would have to come up with the additional money needed to complete and run the project. This would raise the cost of the electricity for the consumers of the power from Young Unit 2 in North Dakota and Minnesota.

The analysis shown in Figure 6 is premised on a set of what we believe are conservative assumptions:

1. The capital cost of any retrofit would fall within the \$1 billion to \$1.6 billion range identified by Minnkota.
2. After being retrofitted, Young Unit 2 would operate at the same capacity factor and produce the same amount of CO₂ as it has averaged between 2015 and 2019. In other words, the operating performance of the unit would not decline at any point before 2038. This is clearly an optimistic assumption, given that the unit already is 43 years old.
3. Young Unit 2 would capture 90% of the CO₂ it produces in each year between 2026 and 2037.
4. All the CO₂ captured at Young Unit 2 is assumed to be either (a) sequestered and, therefore, eligible for the \$50 per metric ton tax credit (escalated by the rate of inflation starting in 2027) or (b) sold for enhanced oil recovery at a price of \$15 per metric ton, in addition to being eligible for a tax credit of \$35 per metric ton.
5. Young Unit 2 would operate for the entire 12-year period after it has been retrofitted.

In addition, we have assumed discount rates of 12% and 15%. This is necessary and appropriate, as Mr. Posner has explained:

“When a tax equity investor invests in a project, it offers up-front cash for the project in exchange for access to the future tax credits. Because there is risk that the credits may not materialize and because investors require a return on their investment that will be recovered over time, tax equity providers “discount” the nominal value of projected tax credits. If a project’s future tax credit cash flows are seen to be riskier – say, because of an unproven technology, an unclear regulatory regime, or operational assumptions that are aggressive—investors will apply a higher rate. When a tax equity investor increases the discount rate on the projected stream of tax credits, this lowers

the value of the tax credits to the project developer.”²⁸

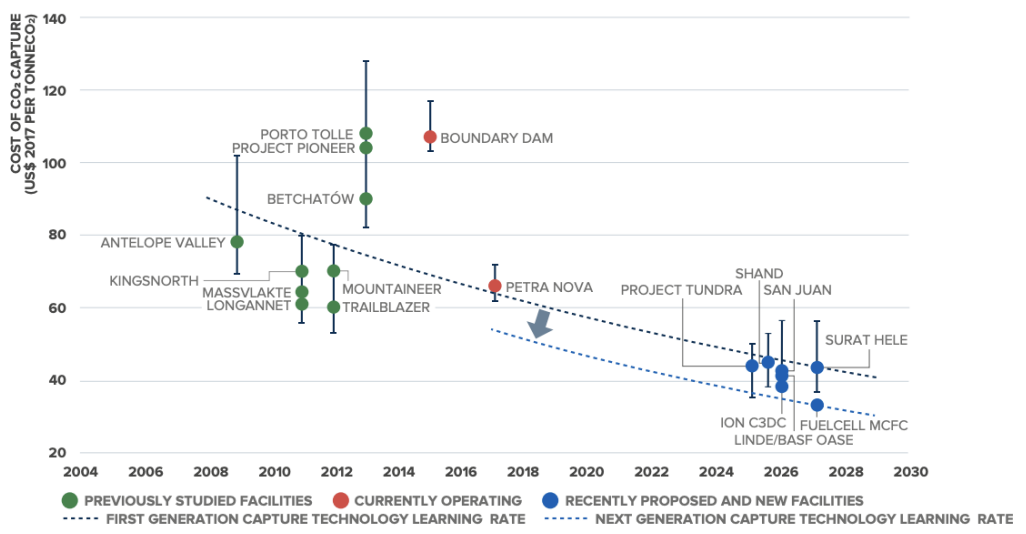
Obviously, there would be an even larger financing shortfall than shown in Figure 6 if (a) the capital cost of the retrofit is above \$1.6 billion; (b) Young Unit 2’s operating performance declines, and it therefore produces less CO₂; (c) Project Tundra fails to capture 90% of the CO₂ in one or more years; or (d) the unit is retired before the end of 12 years.

Risk No. 4: Uncertainty Regarding the Cost of Capturing the CO₂ Produced by Young Unit 2

Although no evidence has been made public as to the actual cost of capturing CO₂ at either Boundary Dam 3 or Petra Nova, the U.S. Department of Energy and other proponents of CCS have reported that the current cost of capturing CO₂ from coal plants is in the range of \$60 to \$65 per metric ton.²⁹ It also has been acknowledged that this cost is far too high and must be reduced to about \$30 per metric ton by 2030 for carbon capture to be financially viable.³⁰

Proponents of carbon capture use a chart from the Global CCS Institute’s *2019 Global CCS Status Report* to show that there are declining costs associated with carbon capture technology maturation based on “industry reports that show a downward trend in coal technology costs.” This chart is reproduced below as Figure 7.

Figure 7: Misleading Claim of Downward Trend in Carbon Capture Costs



Source: *Global CCS Institute’s 2019 Global CCS Status Report, Figure 8.*

²⁸ *Ibid*, pp. 7-8.

²⁹ S&P Global. [US DOE wants to cut carbon capture costs 50%, official touts CO₂ already stored.](#) June 11, 2020. Also: IEA. [Carbon Capture Utilisation and Storage – Status Barriers and Potential, CCC/304.](#) July 28, 2020.

³⁰ *Ibid*.

Unfortunately, this figure is misleading in several ways and paints a false picture of carbon capture costs.

First, the only two potentially accurate capture costs shown in Figure 7 are the \$60 to \$65 cost for Petra Nova and the \$100-plus cost for Boundary Dam. We say “potentially actual” because no actual operating costs have been released for Petra Nova or Boundary Dam 3. All the other carbon capture costs shown in the figure are merely estimates either for past projects that have not been built or for future projects that have not been built yet and may never be built.

Consequently, Figure 7 really only shows that proponents of future carbon capture projects are forecasting or assuming that the cost of capturing CO₂ at their projects will be lower than what they think Boundary Dam and Petra Nova have cost. But there is no real, hard construction and operating cost experience to back up their assumptions and, as such, there is no declining trend in the cost of carbon capture, as Figure 7 misleadingly implies.

Second, the range of costs shown for the various projects in Figure 7 are leveled costs of capturing carbon that in all, or at best, nearly all cases also are merely based on estimates and do not represent actual operating cost data.

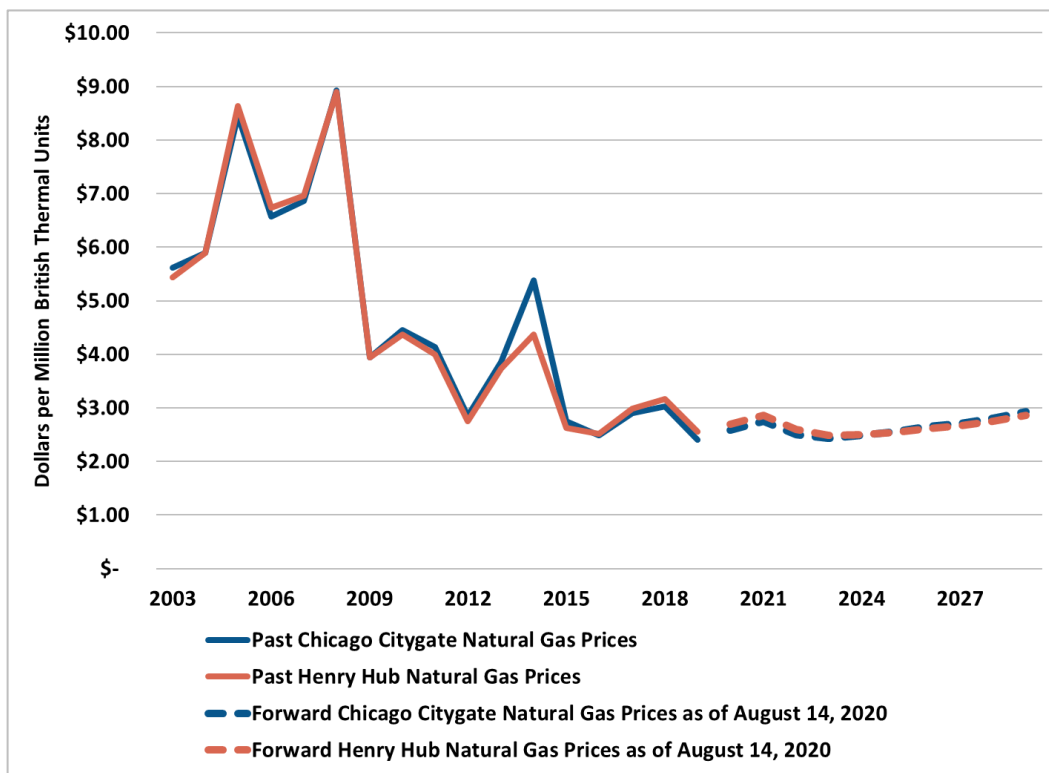
Third, the leveled costs shown in Figure 7 assume that each project achieves an 85% capacity factor. In reality, Petra Nova has only achieved an average 66% to 72% capacity factor at most since it began commercial operations in January 2017. There has been no public information that we have seen on the actual operating performance of Boundary Dam Unit 3 since it was retrofitted for carbon capture but it is clear from monthly operating reports published by SaskPower that it has not come close to an 85% capacity factor. Consequently, the actual leveled cost of carbon capture at both facilities is likely higher (and probably significantly higher) than this figure suggests.

Risk No. 5: Young Unit 2 Already Is a High-Cost Generator and Can Be Expected To Be Even More Expensive If Retrofitted for Carbon Capture

U.S. coal plants have become increasingly uneconomic over the past 10 years due to changing market forces including low natural gas and energy market prices, and growing competition from declining cost renewable resources and storage—wind, in the case of the Midcontinent Independent System Operator (MISO) market where Young Unit 2 is located.

Natural Gas Prices

Gas prices at U.S. trading hubs, including those in the MISO service territory, have declined significantly since 2008 and are expected to remain low for the foreseeable future, as can be seen in Figure 8.

Figure 8: Past and Market Expectations for Future U.S. Natural Gas Prices

Sources: S&P Global Market Intelligence, OTC Global Holdings.³¹

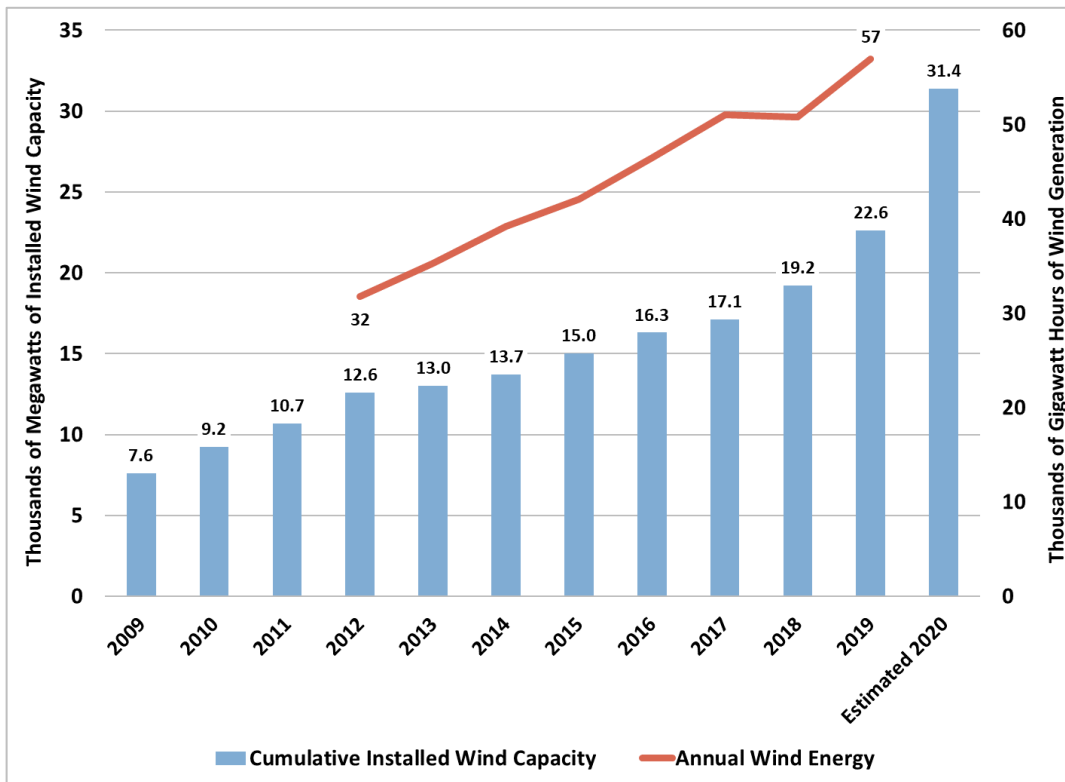
Persistently low prices will undermine the financial viability of the proposed Young Unit 2 carbon capture retrofit by reducing fuel costs for competing gas-fired plants in the region. This, in turn, will lead to (a) lower energy market prices and (b) increased generation at gas-fired plants, displacing generation otherwise produced at coal plants and lowering their capacity factors.

Growing Competition from Wind and Solar Resources and Storage

Installed wind capacity and generation in MISO have increased dramatically in the past decade. Installed wind capacity increased 145% between 2010 and 2019, with another giant leap expected in 2020. Wind generation nearly tripled between 2010 and 2019, with additional significant growth expected in coming years, further increasing the competition for Young Unit 2.

³¹ The forward prices in Figure 6 represent the market's view of future gas prices. Past Natural Gas Prices downloaded from S&P Global Market Intelligence on January 24, 2020. Forward prices from OTC Global Holdings, also downloaded from S&P Global Market Intelligence on August 15, 2020.

Figure 9: Rapid Growth in the Past Decade in Installed Wind Capacity and Annual Wind Generation in MISO



Sources: MISO Annual State of Market Reports and Monthly Market Operations Reports.³²

Installed solar capacity in MISO more than doubled between December 2018 and March 2020, and solar generation increased by 70% between 2017 and the 12 months ending in March 2020.³³

As the amount of installed renewable generation has climbed, the prices of buying power from wind and solar resources have fallen.

Data from Lawrence Berkeley National Laboratory (LBNL) shows that the prices of wind power purchase agreements (PPAs) have fallen dramatically in all regions of the country. Prices for the best wind resources in the Interior region (including those in the Dakotas) averaged \$57/MWh in 2009; today, PPAs in those same areas are below \$20/MWh.³⁴ Wind prices in the rest of the country have fallen sharply as well, dropping from an average of roughly \$90/MWh in 2010 to less than \$30/MWh in 2018.

As wind prices have declined, the performance of wind turbines has improved,

³² MISO State of the Market Reports and MISO Monthly Operations Reports.

³³ MISO Monthly Operations Reports.

³⁴ U.S. Department of Energy. 2018 Wind Technologies Market Report. August 2019, p. 59.

driven in part by larger turbines mounted on taller towers and featuring longer blades.³⁵

The same trend of declining PPA prices is evident in the solar industry, with prices declining by more than 80%.³⁶ Current PPA prices are now commonly below \$50/MWh and often significantly less. In a review of 38 PPAs signed since 2017, LBNL found that 27 were priced below \$40/MWh, with 21 less than \$30/MWh and four under \$20/MWh (all levelized, in 2018 dollars).³⁷ Significantly, the LBNL survey also found that 23 of the PPAs included battery storage of four to five hours and that these projects were not much more expensive than the PPAs from solar-only projects.³⁸ Solar PPA prices also are expected to continue to decline over time.

At the same time that renewable capacity and generation in MISO have been growing, the 2019 MISO forecasts for energy sales and peak demand are relatively flat through 2039 (projecting annual compound growth of less than 1%).³⁹ The forecast was the same for MISO's Load Resource Zone 1, which includes Minnesota and North Dakota.⁴⁰ These forecasts were completed before the COVID-19 pandemic, which can be expected to reduce energy and peak demand growth, even from the low levels forecast in late 2019.

Energy Market Prices

Due to low natural gas prices and the increasing competition from declining cost renewable resources, energy market prices in the northern zone of MISO have been low for most of the past decade and are expected to remain low for the foreseeable future.

³⁵ Lawrence Berkeley National Laboratory. [Wind Technologies Market Report](#). August 2020.

³⁶ Lawrence Berkeley National Laboratory. [Utility-Scale Solar](#). December 2019. Prices cited here are levelized in 2018 U.S. dollars and include any contract escalation clauses.

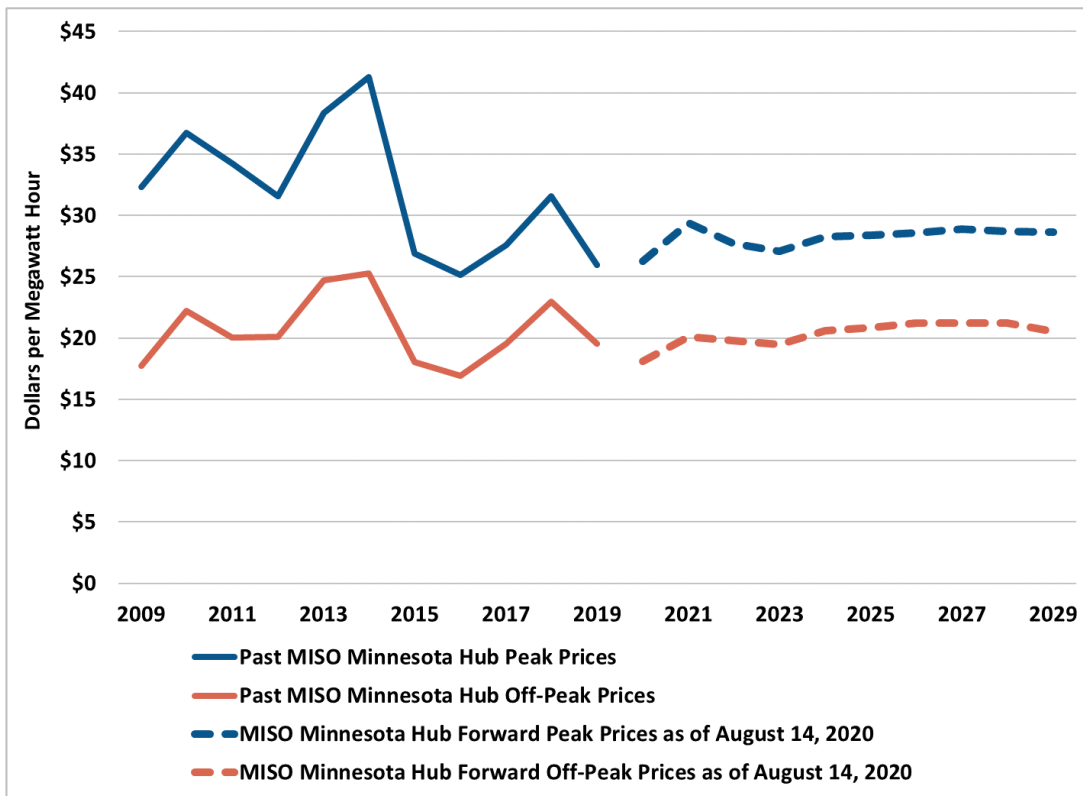
³⁷ *Ibid.*

³⁸ *Ibid.*

³⁹ State Utility Forecasting Group. [2019 MISO Energy and Peak Demand Forecasting for System Planning](#). November 2019, p. 2.

⁴⁰ *Ibid.*, pp. 27-28.

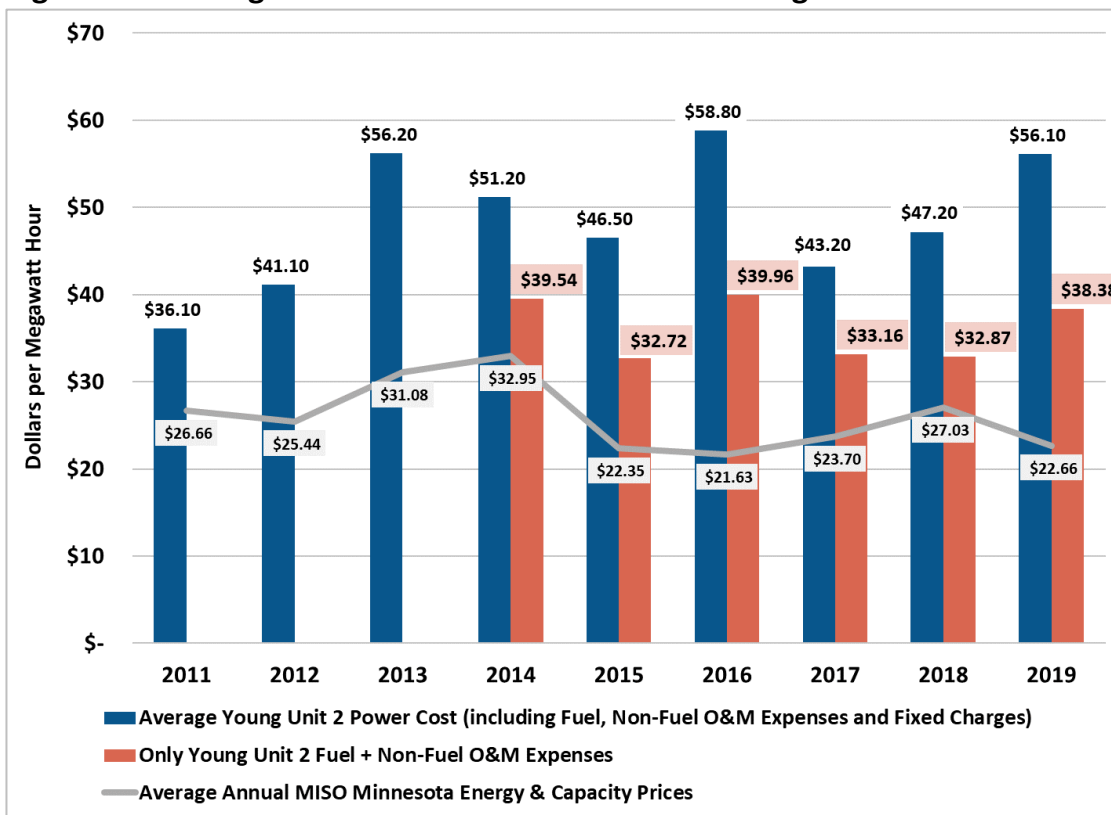
Figure 10: MISO Energy Market Prices



Sources: S&P Global Market Intelligence and OTC Global Holdings.

Although Minnkota has claimed that the Young Station “produces low-cost power for consumers in North Dakota and Minnesota,”⁴¹ this is clearly not true for Young Unit 2.

⁴¹ Project Tundra website.

Figure 11: The High Cost of Power from Milton R. Young Unit 2⁴²

Sources: Square Butte Annual Reports for 2015 through 2018.

As the figure clearly shows, Young Unit 2's average cost of power since at least 2011 has been significantly higher than the costs of purchasing the same amounts of power from MISO. IEEFA estimates that between 2011 and 2019, ratepayers of Minnesota Power and the cooperatives that buy their power from Minnkota paid \$455 million more for power from Young Unit 2 than they would have paid for the same power from the MISO markets. Even ignoring Young Unit 2's fixed charges, just the cost of producing power at the unit (only fuel plus non-fuel O&M expenses) was almost \$200 million higher than buying the same power in the market.

Yet, despite the much cheaper prices available in MISO, Minnkota has purchased only small amounts of power in the marketplace since 2015—averaging just 293,999 MWh, or 4.8% of its joint system energy requirements. Instead of saving its members money by purchasing cheaper MISO energy, Minnkota has preferred to generate more expensive power at its own coal plants, including Young Unit 2.

Minnkota has indicated its intention to continue purchasing only small amounts of the low-cost power available in the MISO market in coming years. Its 2019 IRP states that Minnkota's joint system purchases from MISO will range from a low of

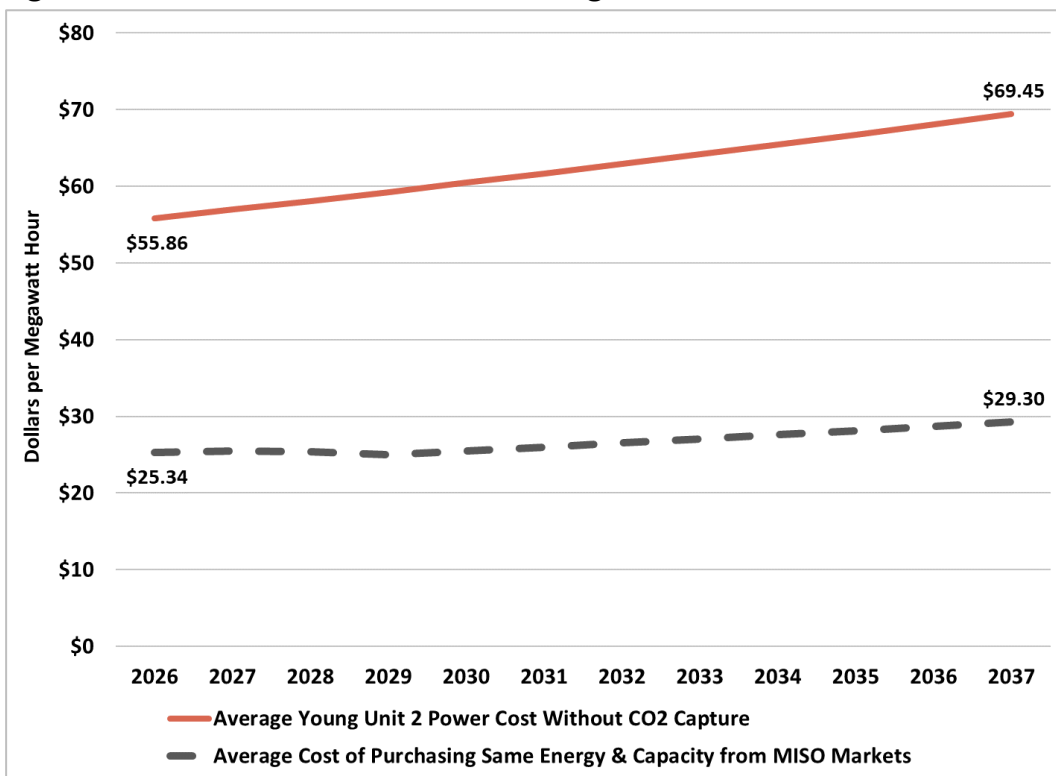
⁴² The average power costs in Figure 10 represent Unit 2's annual fuel and non-fuel Operating & Maintenance expenses plus the fixed charges for the plant. These fixed charges include interest, depreciation and income taxes.

0.3% to a high of 2.4% of its total annual energy requirements—even less than Minnkota has been purchasing in recent years.

Power from Young Unit 2 Will Remain Very Expensive Regardless of Whether it is Retrofitted for Carbon Capture

Low prices for the foreseeable future in the MISO energy markets mean that even if it is not retrofitted for carbon capture, the cost of power from Young Unit 2 will remain substantially more expensive than purchasing the same energy and capacity from the marketplace.

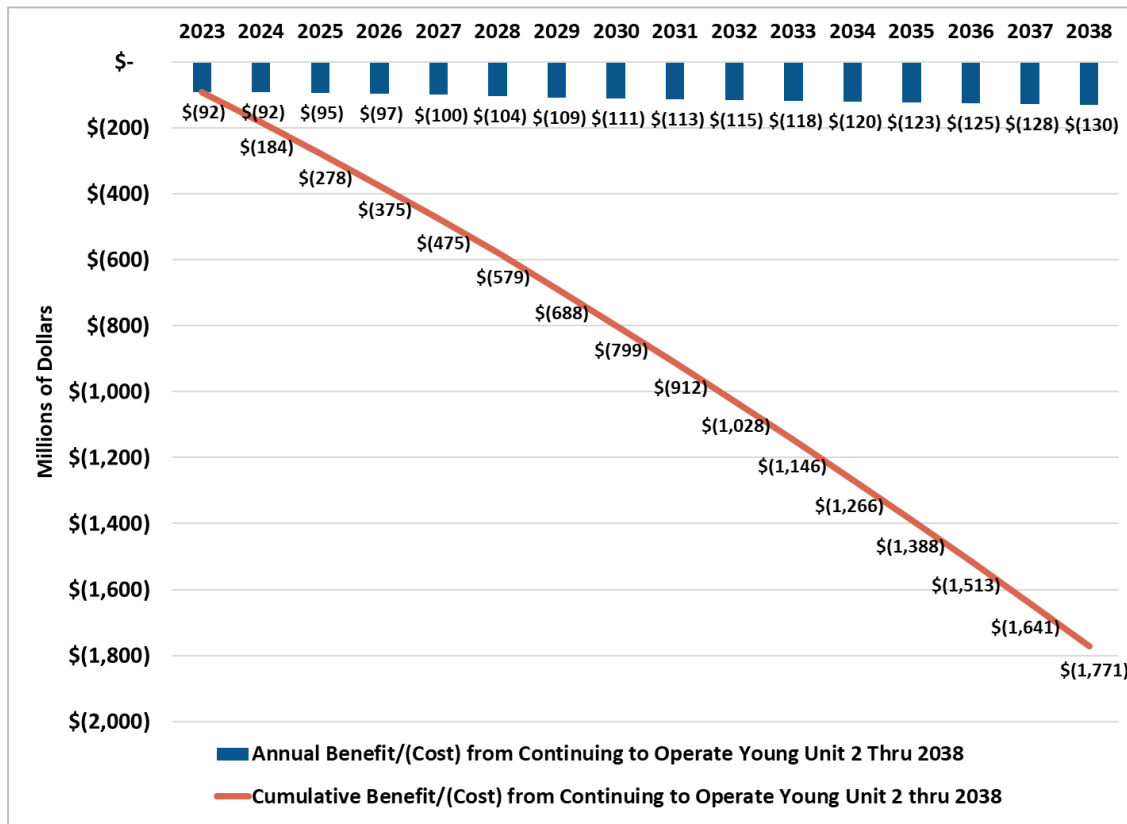
Figure 12: The Future Economics of Young Unit 2



Source: IEEFA analysis.

As a result, continuing to operate Young Unit 2 between 2023, when construction of the new carbon capture facility is projected to begin, and 2038 would cost the ratepayers of the co-ops that buy power from Minnkota \$1.77 billion more than if the co-ops purchased the same amounts of energy and capacity each year from the MISO competitive wholesale markets.

Figure 13: The Benefits/(Costs) of Continuing to Operate Milton R. Young Unit 2 vs. Buying the Same Amounts of Capacity and Energy from MISO



The analysis presented in Figures 12 and 13 reflects the following assumptions:

- Young Unit 2 would operate from 2026 to 2040 at the same annual average capacity factor as it achieved between 2015 and 2019. There is no assumption that the plant’s operating performance will degrade as it ages.
- The average power costs between 2026 and 2040 would be based on its average power cost for 2015 to 2019, escalated at a 2% annual rate starting in 2020.
- Energy market prices through 2029 are based on forward MISO price strips as of Aug. 14, and escalated at 5% annually in subsequent years.

The analysis does not reflect any of the construction or operating costs of the new carbon capture facility and associated infrastructure that could be passed along to Minnkota’s co-op owners and their ratepayers. It also does not include any of the potential costs of sequestering captured CO₂. However, the cost of operating and maintaining Young Unit 2 almost certainly will become even more expensive if it is retrofitted for carbon capture.

All fossil-fired power plants consume a portion of the power they generate to run necessary onsite equipment. For example, Young Unit 2 has averaged a parasitic load of about 8% of the unit's gross generation. The parasitic loads for a coal plant retrofitted for carbon capture are projected to be much higher, somewhere in the range of 25% to 35% of the unit's gross generation, in large part because a significant amount of steam from the power plant is used in the capture process.⁴³ Minnkota has indicated that "Project Tundra can result in ~ 300 MW net of near 'zero carbon' power for sale to our members with limited or no increase in cost."⁴⁴ Young Unit 2 is currently a net 455MW generator. So, it appears that Minnkota currently expects the unit's parasitic load will increase to about 35% of its gross generation.

The impact of Project Tundra on Minnkota's customers will depend on how they decide to charge for the electricity and steam used by the new carbon capture facility and associated infrastructure. If the answer is that the new facility will be treated as just another load on the system, then it should be charged for the same full production cost as other customers pay at an average dollar-per-MWh price that reflects all fuel, non-fuel O&M and fixed costs.

However, if Minnkota has a financial relationship with Project Tundra and the developer of the carbon capture facility and associated infrastructure, that would open the door to other costs for Minnkota, its owner co-ops, and their ratepayers. For example, to keep the cost of capture low Minnkota could decide to charge the carbon capture facility for only a portion of the fuel, non-fuel O&M and fixed costs it charges its co-op owners and their ratepayers. Or the carbon capture facility might not recover its full cost of capturing and sequestering CO₂ through EOR or sequestration. This might happen because those costs are higher than anticipated; the revenues from selling the captured CO₂ for EOR are lower than expected; or the retrofitted plant simply does not capture as much CO₂ as projected. Any of these would substantially affect the costs paid by Minnkota's owner cooperatives and their ratepayers.

In addition, if Project Tundra is considered a joint venture, Minnkota might be responsible for obtaining some of the additional funding necessary to build the new carbon capture facility and associated infrastructure if the estimated number of 45Q tax credits don't fully fund the project.

It also is possible that the Young Unit 2 retrofit would have an adverse impact on the plant's operating performance (e.g., result in a higher heat rate) or raise other plant costs, which would increase costs for ratepayers.

Moreover, depending on the financial relationship between Minnkota and the owner/investors in the new carbon capture facility and associated infrastructure, there would be additional costs after retrofitting that would be specifically related to the carbon capture process. Such costs would include additional operating,

⁴³ Enchant Energy. [San Juan Generating Station—Units 1&4, CO2 Capture Pre-Feasibility Study](#). July 8, 2019.

⁴⁴ Minnkota Power Cooperative. [In the Matter of Minnkota Power Cooperative, Inc.'s 2019 Resource Plan](#). June 28, 2019, p. 40.

maintenance and administrative staff; acquisition of more water; and higher water treatment, steam, chemical and disposal costs for the carbon capture facility. These costs would be passed along to ratepayers as well.

Finally, it is reasonable to expect significant capitalized maintenance expenditures will be required during the extended operating lives of any retrofitted coal units, for both the plant's carbon capture-related and its non-carbon capture-related equipment. Such expenditures most likely would be added to the company's rate base, forcing ratepayers to pay again.

It can be expected that these costs would fall in the range of millions to tens of millions of dollars, depending on the size of the coal unit retrofitted.

Unlike Minnkota, Other Utilities Are Transitioning Away from Coal Towards Proven Technologies

As early as 2013, Minnesota Power decided to phase out its contract to purchase 227 MW from Young Unit 2 by 2026 as part of a plan for meeting Minnesota's goals for greenhouse gas reductions.⁴⁵ The company reaffirmed this plan in its 2015 IRP, explaining that:

*Minnesota Power has used imagination and innovation in rebalancing its generation fleet. Young 2, a major source of coal-based generation, is being phased out of the Company's resource mix as this coal generation is being replaced by wind energy.*⁴⁶

and:

*The Preferred Plan [which included phasing out Young Unit 2] continues the transition of Minnesota Power's fleet to be more diverse, flexible and lower emitting ... The Preferred Plan protects affordability, preserves reliability, and sustains environmental stewardship.*⁴⁷

In early May, Great River Energy (GRE) announced that it was closing its Coal Creek Station in North Dakota, one of the largest coal plants in the Upper Midwest, and replacing it with 1,100 MW of new wind power.⁴⁸ GRE said its plan to phase out coal resources, add significant renewable energy and explore grid-scale battery storage would "significantly reduce [its] member-owners supply costs."⁴⁹

GRE Chief Executive Officer David Saggau said that the real driver for the decision to close Coal Creek in favor of wind and storage "is economics."⁵⁰ He also said after

⁴⁵ Minnesota Power. [2013 Resource Plan](#). March 1, 2013, p. 71.

⁴⁶ Minnesota Power. [2015 Integrated Resource Plan](#). September 1, 2015, p. 2.

⁴⁷ *Ibid.*, p. 69.

⁴⁸ Great River Energy. [Major power supply changes to reduce costs to member-owner cooperatives](#). May 7, 2020.

⁴⁹ *Ibid.*

⁵⁰ Star Tribune. [Minnesota's Great River Energy closing coal plant, switching to two-thirds wind power](#). May 7, 2020.

Coal Creek is closed in the second half of 2022, GRE would voluntarily continue to make local tax payments for five years, totalling \$15 million.

Coal Creek is more than twice as large as Young Unit 2, slightly younger, and has been a better performer in recent years.

Market Uncertainties Cloud Outlook for Both EOR-Dependent Carbon Capture and Geologic Storage

The speculative economics associated with carbon capture projects at coal-fired power plants all depend on one key element—the ability to either sell the captured CO₂ to oil companies interested in using the gas for enhanced oil recovery projects or to permanently sequester the captured CO₂ underground.

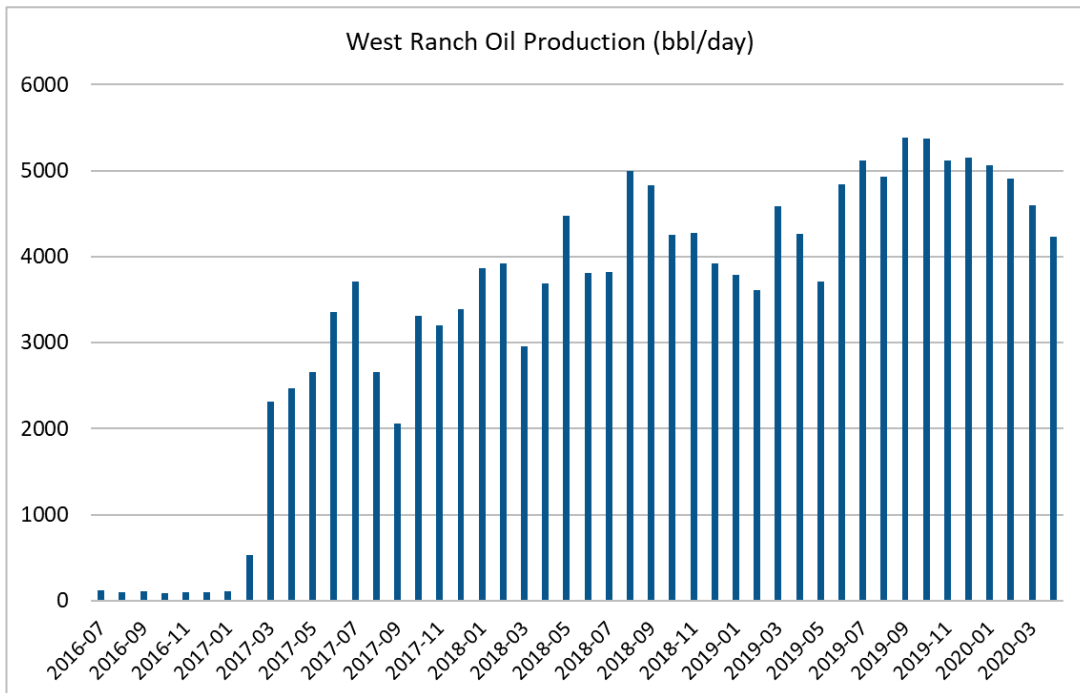
As outlined on its web site, Project Tundra's preferred option is to store captured CO₂ in a nearby underground geologic repository, but the possibility of using the CO₂ for EOR activities apparently has not been ruled out. Both options have serious drawbacks that could further undercut the project's tenuous economics.

The EOR Option

On July 28, 2020 NRG, the operator and 50% owner of Petra Nova, announced it had suspended the capture of CO₂ and mothballed the project due to low oil prices. NRG's announcement must represent a flashing warning sign for anyone considering retrofitting a coal plant for carbon capture or investing in such a project due to the significant market risks associated with using captured CO₂ for EOR.

NRG originally said the CO₂ captured at Petra Nova would be used to increase oil production at its West Ranch field to 15,000 barrels/day (b/d) from less than 1,000 b/d. However, as shown in the figure below, daily production from the beginning of 2017 through the first four months of 2020 has only rarely topped 5,000 b/d.

Figure 14: Actual vs. Estimated Daily Production at NRG’s West Ranch Oil Field



Source: TexasDrilling.com.

Even before NRG’s July 28th announcement, it was clear that the Petra Nova project has not been as profitable as NRG expected, if it has been profitable at all. Indeed, the company has taken impairments of almost all of its equity investment in its subsidiary Petra Nova Parish Holdings.

According to company financial reports, it invested \$300 million to bring the Petra Nova project online. However, in the past four years, NRG has recorded three separate impairment charges related to the plant and Petra Nova Parish Holdings, the subsidiary that operates the facility. These charges have totalled \$310 million.

The first charge, in 2016, before the project was even complete, was \$140 million. At the time, NRG cited declining oil prices as the reason for the impairment.⁵¹ NRG took a second impairment of \$69 million in its investment in Petra Nova in 2017 based on a revised view of oil production expectations.⁵² The last impairment, for \$101 million, was taken in 2019.⁵³

The profitability of retrofitting Young Unit 2 for carbon capture and using the captured CO₂ for EOR will be affected by actual and expected oil prices and by the competition among different CO₂ sources. Given the inherent volatility of oil prices

⁵¹ NRG Energy, Inc. [Form 10-K](#). February 28, 2017.

⁵² NRG Energy, Inc. [Form 10-K](#). March 1, 2018.

⁵³ NRG Energy Inc. [Form 10-K](#). February 27, 2020.

and current futures prices, the project may not be financially viable despite Minnkota's claims.

NRG hasn't just struggled to turn a profit with its EOR activities. The spring oil price crash and continuing uncertainty in the market have prompted significant cuts in planned capital spending by oil and gas companies across the sector, hitting particularly hard at two of the country's leading EOR companies, Occidental Petroleum and Denbury Resources.

Occidental, which has extensive EOR operations in the Permian Basin, saw its stock price drop from \$42.97 on Feb. 20 to \$12.51 on March 9. Its stock has traded in a narrow range since and closed Sept. 4 at \$12.25. The economic turmoil has also prompted the company to slash its dividend to just a penny per share. The company cut the dividend in late May after an earlier cut in March—the first in 30 years—to \$0.11 a share from \$0.79. It also has significantly reduced its capital spending plans for 2020.

Denbury Resources, which has CO₂ EOR projects in both the Gulf Coast and Rocky Mountains, has fared even worse, declaring bankruptcy in July in an effort to clear its books of \$2 billion in debt.

Any EOR activity also would require the construction of a pipeline to transport the CO₂ from the Young plant, which is located north of Bismarck in the center of the state, to the oil-rich Bakken fields 100 miles or more to the west.

The current uncertainty about EOR is not unique. For example, a November 2018 IEA report noted that there had been an 18 percent decline in oil production from North American EOR between 2014 and 2018.⁵⁴ The report pointed to several obstacles that have hindered EOR, pointing in particular to its cost disadvantage versus fracking. The current price crash only accentuates EOR's inability to compete with lower-cost producers.

Geologic Storage

The upheaval in the oil and gas sector may make geologic storage appear less risky, but there are plenty of potential pitfalls with this option as well.

In particular, without potential oil or CO₂ sales revenue, Project Tundra will be forced to finance its entire capital cost through the tax equity market. There, the project will have to compete for financing with more developed, less-risky sectors, notably wind and solar generation. These well-established renewable energy sectors are seen as low-risk and reliable performers, traits that would not be attributed to a large, first-of-its-kind underground carbon storage project. This would inevitably force Project Tundra's developers to pay more to raise capital for construction. Raising these funds in the next several years is likely to be even more difficult for untested CCS projects, given the overall slowdown in the U.S. economy.

⁵⁴ IEA. [Whatever happened to enhanced oil recovery?](#) November 28, 2018.

This will reduce the size of the overall tax equity market and could well prompt remaining participants to favor more established projects over CCS.

In addition, the rules governing long-term monitoring and verification of the stored CO₂ have yet to be finalized. The Treasury Department issued proposed rules in May that were generally well-received by officials associated with the CCS industry. Still, the issue remains unresolved and will certainly remain a major source of concern, especially given Treasury's admission that companies claimed almost \$894 million of credits for carbon capture and storage over the past 10 years without following Environmental Protection Agency oversight rules.

There also is no firm public data on the costs of compressing, transporting, injecting and monitoring the CO₂. Given the substantial costs for capturing the carbon in the first place, carbon sequestration-related costs need to be as low as possible to keep the project's overall costs in bounds. Unfortunately for Project Tundra and developers of other CO₂ sequestration projects, such costs may be higher than anticipated. In congressional testimony this summer, former Energy Secretary Ernest Moniz told the Senate Energy and Natural Resources Committee: "While the geologic capacity is available and the technology is known, there are economic and social challenges. The costs of drilling, compressing, injecting and monitoring are estimated to be in the range of \$20-\$25 per ton of CO₂."⁵⁵

If the costs are anywhere near that high, Project Tundra and similar sequestration-based CO₂ capture projects simply will have no chance of funding their initiatives via the \$50-per-ton tax credit, forcing additional costs onto ratepayers or the companies involved.

Conclusion

The Project Tundra proposal is a high-risk option that ignores past power plant experience with CCS technology and long-term trends in U.S. electricity markets that favor clean, cheap renewable energy and storage. In particular, IEEFA finds that:

- The project almost certainly will cost more—perhaps much more—than the unjustifiably optimistic estimates published by its backers;
- Problems are likely in the scale-up of Fluor's capture technology, which has never been used at commercial scale;
- It is highly unlikely the project will be able to consistently capture 90% of the carbon produced by the retrofitted Young unit, calling into question the economic underpinning of the entire project;
- Milton R. Young Unit 2 has been and will continue to be a high-cost generator; and

⁵⁵ Energy Futures Initiative. [Statement for the Record, Ernest J. Moniz, 13th Secretary of Energy, Before the Senate Energy and Natural Resources Committee](#). July 28, 2020, p. 8.

- Continued declines in price and improvements in performance by wind, solar and storage technologies will undercut electricity generation from the Young unit, reducing the amount of CO₂ it generates and consequently reducing potential income from the federal government's 45Q tax credits.

In sum, Project Tundra is a risk that the region's cooperative utilities and ratepayers simply cannot afford.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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