PEMBINA institute

Modelled aspects of the Alberta electricity system

Peaking capacity, supply adequacy and simple cycle gas plant operations

Will Noel, Binnu Jeyakumar, Ben Thibault, Scott MacDougall | November 2, 2023

This modelling is part of the Pembina Institute's response to the draft Clean Electricity Regulations, submitted to Environment and Climate Change Canada on November 2, 2023. It provides analysis of providing peaking capacity through energy storage, supply adequacy and gas plant operations, within the context of key elements of the draft CER.

Context

This modelling addresses Pembina's recommendations for the draft CER's provisions of the following three elements:

1. Peaker exemptions

To allow emitting facilities to "operate at any emissions intensity for a maximum of 450 hours per year, with an [emissions] limit of 150 kt/yr, to provide back-up or peaking capacity."[1]

Peaking power plants (or "peakers") are characterized by their ability to rapidly respond to changes in electricity demand and availability of other generation supply. In electricity grids without sufficient hydroelectric resources or transmission interties — such as Alberta and Saskatchewan — this fast-response balancing role has typically been filled by simple cycle natural gas plants.

Given the global effort to achieve grid decarbonization, including in jurisdictions that presently rely on unabated thermal generation for "peaking," the alternative options available — including rapidly dispatchable non-emitting generation, storage, demand-side management and interconnections — are certain to expand and improve economically. Combined with grid modernization efforts, rising electricity demand due

[1] Government of Canada, "Clean Electricity Regulations," *Canada Gazette Part I,* 157, no. 33, August 19, 2023, 2733. https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/pdf/g1-15733.pdf

to electrification will offer new opportunities for valuable demand-side management — and greater capacities of wind, solar, and energy storage.

Analysis A. of peaking capacity shows that adding battery capacity to Alberta's simple cycle plants could displace 40 to 80% of the operating hours and generation of these plants. Batteries could be recharged at low cost through wind and solar generation.

Analysis B., addressing supply adequacy, shows that the combination of storage with a strong complement of wind will support supply adequacy even in the most challenging and lowest-wind hours.

Analysis C. of gas plant operations shows that, due to the unfavourable economics of simple cycle natural gas plants in an increasingly decarbonized electricity system, facilities that are still within their amortization period would require additional revenue streams in order to make a return on investment — regardless of the CER's unabated peaker exemption limit.

2. End of Prescribed Life (EoPL)

To "Phase in the performance standard on existing units by applying the standard to any given unit 20 years following its commissioning date, known as a unit's End of Prescribed Life." [2]

The 20-year EoPL already enables the orderly transition away from unabated thermal generation. Year by year, as plants hit the 20-year EoPL, operators can decide whether to abate, work within the peaker exemption, or retire the facility. This means that units will be retired gradually rather than all together when the regulations come into effect.

Analysis B. of supply adequacy indicates that a 20-year EoPL, combined with a 450-hr unabated peaker exemption, is adequate to support reliability.

3. Cogeneration and behind-the-fence-generation

"In any given compliance year, industrial units that have net exports to a NERC-regulated electricity system (i.e. they sell more electricity than they buy) would have to meet the proposed Regulations' performance standard in that year." [3]

In Alberta, industrial cogeneration forms a large proportion of Alberta's electricity system. Typically, these facilities are oversized relative to their behind-the-fence

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[2] "Clean Electricity Regulations," 2731.

[3] "Clean Electricity Regulations," 2734.

electricity demand. While their operations may be conjoined with other industrial production, they are electricity generators and electricity market participants by any definition.

However, cogeneration does not provide as much value for grid reliability or balancing as some competitors. Given that the electricity generation is secondary to the primary industrial operations' requirement for steam or heat, its generation is much less flexible or responsive to grid needs.

Analysis B., which addresses supply adequacy (and assumed that cogeneration that hits EoPL will cease to export to the grid), shows that grid reliability can be sustained under a 20-year EoPL and with a 450-hour limit to the peaker exemption, even without cogeneration export.

The federal CER is a key part of the suite of policies, incentives and regulations to support decarbonizing our electricity sector as we move towards a net-zero economy. The Pembina Institute is pleased to have had the opportunity to provide insights and recommendations into how the CER can deliver a credible, affordable and reliable net-zero grid in Canada, with significant emissions reductions by 2035.

Analyses

A. Peaking capacity through storage

Storage technology that already exists today could supplant the majority of the role of simple cycle natural gas plants in providing peaking capacity.

Alberta currently has 25 simple cycle natural gas plants with a total fleet capacity of approximately 1 GW. Some of these assets are not run as peaking facilities as their operation is dependant on factors outside the bulk electricity system.[4] Figure 1 shows the range of dispatch hours for each individual simple cycle plant that operates as a peaker, where each dispatch is classified by the amount of time the plant is operating continuously until it is sent the signal to shut off. Figure 2 shows the amount of electricity generated during each of those dispatches. Together, these figures show that the majority of Alberta's peaking fleet is dispatched for five to 15 hours each time it is

[4] For example, the primary function of the Rainbow #5 simple cycle plant is to provide electricity to the Rainbow Lake natural gas processing plant with which it is co-located. Similarly, the West Cadotte simple cycle plant uses diverted flare gas from the adjacent facility.

called upon and that the electricity generated during those hours ranges, on average, from under 1 MWh to 1,500 MWh, owing largely to differences in capacity. Due to the infrequency of operation and the limited total operating hours of these assets, short-duration energy storage options already available today could serve much, if not all, of their function, recharging between dispatches. This non-emitting option will only become more feasible as storage technology proliferates and improves (in capital cost and efficiency).

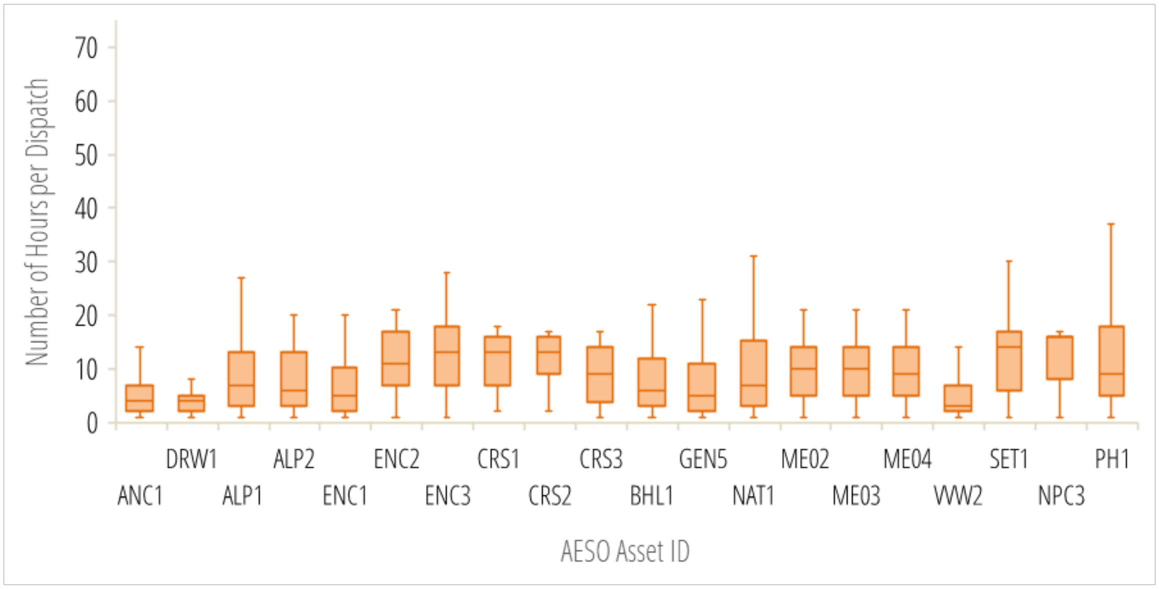

Figure 1. Dispatch hours for Alberta simple cycle assets, 2022

Data source: Alberta Electric System Operator[5]

[5] Alberta Electric System Operator, "Market and System Reporting: Metered Volumes." https://www.aeso.ca/market/market-and-system-reporting/

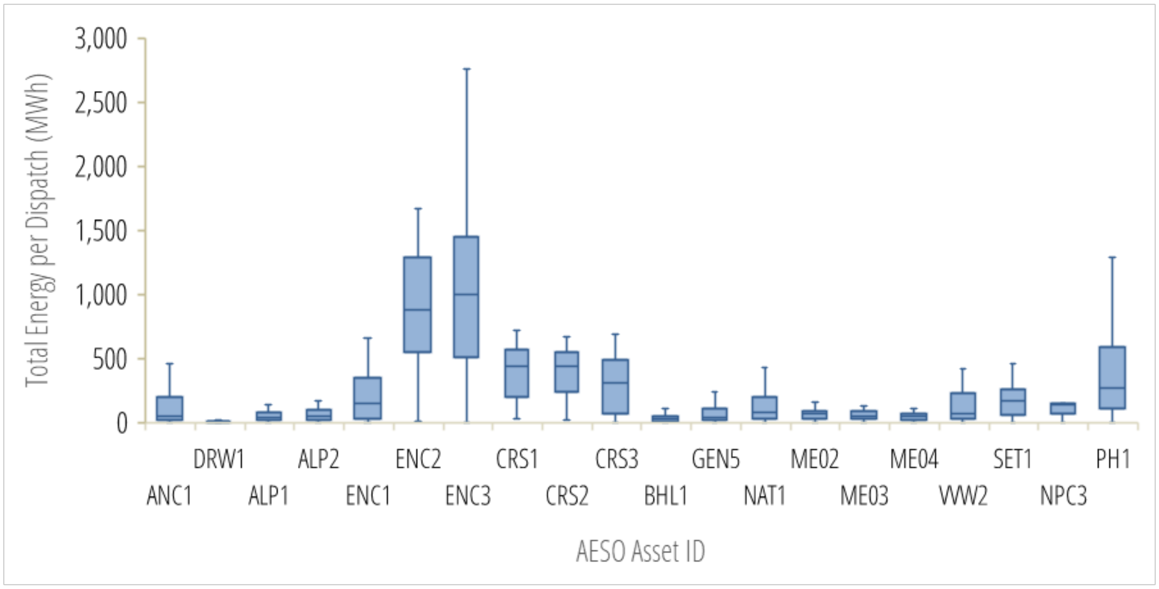

Figure 2. Electricity generation per dispatch of Alberta simple cycle assets, 2022

Data source: Alberta Electric System Operator[6]

Figure 3 shows the significant decrease in 2022 peaking unit operating hours that could have been achieved through the addition of a battery. For example, augmenting each simple cycle plant with a 4-hour battery of the same installed capacity — 803 MW in total — could displace nearly half of the generation and operating hours of the original fleet. Similarly, co-locating each simple cycle plant with 100 MW of 4-hour storage could cover more than two-thirds of the generation and 80% of the operating hours. While this simple analysis assumes that the energy storage assets would be fully charged prior to being dispatched, the continued expansion of Alberta's wind and solar fleets will provide ample opportunity for low-cost charging. As such, the need for unabated gas for peaking requirements is already a matter of debate, not a settled assumption, never mind with the advancements in non- or low-emitting technology 12 years out.

[6] "Metered Volumes."

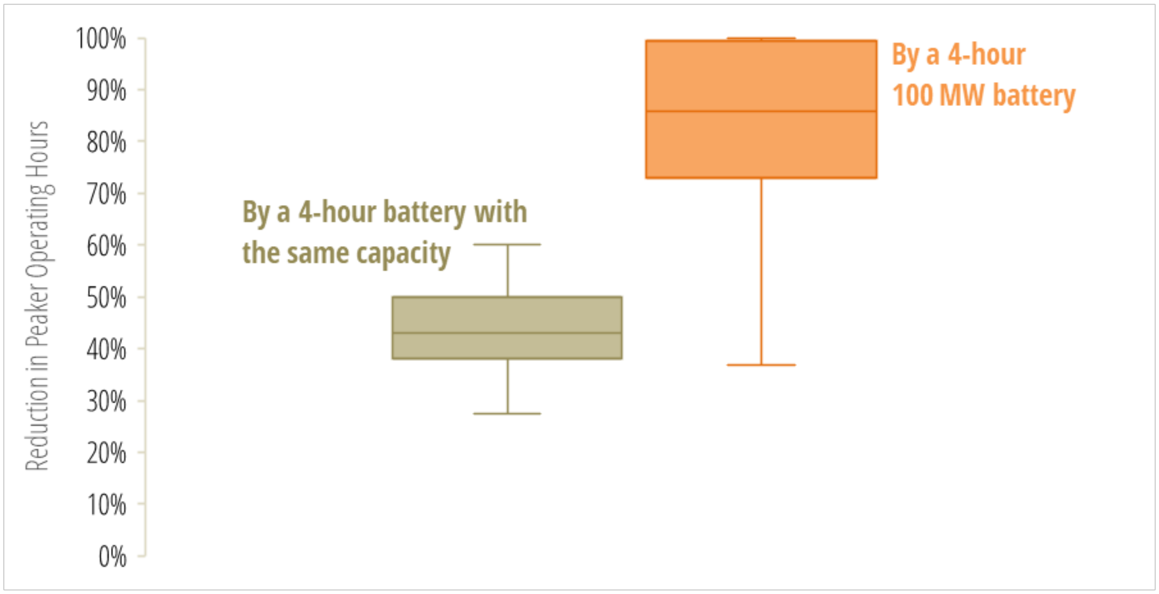

Figure 3. Decrease in simple cycle operating hours through the addition of different sizes of battery, 2022

B. Supply adequacy

To quantify the potential risk of unserved energy in 2035, we looked at a worst-case scenario analysis of Alberta's electricity grid, considering a range of fleet mixes including firm generation, renewables, intertie availability, and energy storage.

Modelling assumptions

Our very conservative assumptions for this supply adequacy analysis are as follows:

- Wind assets will follow the same generation pattern as in 2010[7] — a particularly low-wind year in Alberta — scaled up to 2035 installed capacities which conservatively range across the scenarios from 5,000 MW to 10,000 MW.[8]

[7] Alberta Electric System Operator, "Data Requests: Hourly Metered Volume and Pool Price and AIL Data 2010 to 2022," (accessed July 7, 2023). https://www.aeso.ca/market/market-and-system-reporting/data-requests/

[8] The 5,000 MW low end of the scenario range includes existing capacity (3,853 MW) plus approximately 25% of projects in AESO's queue that have met their inclusion criteria as of October 2023. The high end of 10,000 MW includes existing capacity plus all projects that have met inclusion criteria plus 33% of projects that are in the queue but have not met the inclusion criteria. (Alberta Electric System Operator, "October 2023 Connection Project List." https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/) The upper limit considered in this analysis is less than the wind fleets in all six scenarios of

- Hydro assets are derated by 50%.
- Natural gas plants are derated by 13%, based on 2022 outage data,[9] with total installed capacity based on the 20-year End of Prescribed Life (EoPL) set in the draft CER. Only existing assets plus a select few projects under construction with a 2024 commissioning date (Cascade, Base Plant, and Genesee 1 and 2) are included.[10]
- Cogeneration assets that do not fall within the 20-year EoPL are assumed to stop exporting electricity and are removed from the study. In other words, as a worst-case scenario from a generator availability point of view, we assume they will opt to move their operations completely behind the fence rather than abate, a conservative assumption given industry plans for abatement.
- Transmission interties are derated by 20-35%.
- System demand is taken from the Alberta Electric System Operator's Net-Zero Emissions Pathways Report.[11]

Given the assumptions outlined above, we ran an analysis on 12 potential generation fleets with varying levels of installed wind capacity, energy storage capacity, and firm generation availability, including natural gas generators exempt from the CER under the 20-year EoPL provision, interties, hydro, and biomass. Each analysis also includes a fleet of flexible natural gas generators — not including cogeneration or coal-to-gas boilers — that are limited to 450 operating hours per unit.

Results

Figure 4 shows the range of unserved energy resulting from the 450-hour limit placed on gas-fired generation units as well as the number of gas generation hours required to alleviate the unserved energy. Unsurprisingly, the fleets with the lowest available generation capacity (1-3) — resulting from a combination of the lower bookend scenarios for wind (5,000 MW), energy storage (500 MW/2,000 MWh), and intertie utilization (35% derate) — are found to perform the worst of all our analyses, requiring

Zeroing In, which ranged from 10,800 MW to 19,300 MW. (Will Noel and Binnu Jeyakumar, *Zeroing In*, (Pembina Institute, 2023), 46. https://www.pembina.org/pub/zeroing-in)

[9] Alberta Electric System Operator, "Annual market statistics data file," (2023). https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

[10] This does not include the 567 MW of natural gas projects that (as of October 2023) have received regulatory approval, with an expected start date before January 2025, but which are not yet under construction. ("October 2023 Connection Project List.")

[11] Alberta Electric System Operator, "Excel | AESO Net-Zero Emissions Pathways Data File," (2022). https://www.aeso.ca/future-of-electricity/net-zero-emissions-pathways/

an additional 200-325 hours of peaker operations on top of the 450-hour provision. However, under fleet scenarios with higher wind and storage deployment — a more accurate representation of a decarbonized grid and better aligned with recent forecasts including *Zeroing In*[12], *Canada's Energy Future 2023*[13], *Shifting Power*[14], and the IEA's 2023 World Energy Outlook[15] — we find that energy demand is met more consistently and eventually without requiring the full 450 hours peaking provision, meaning a tighter exemption can still enable reliability.[16] This result underscores the importance of a diversity of technologies in ensuring the robust operation of a decarbonized electricity grid.

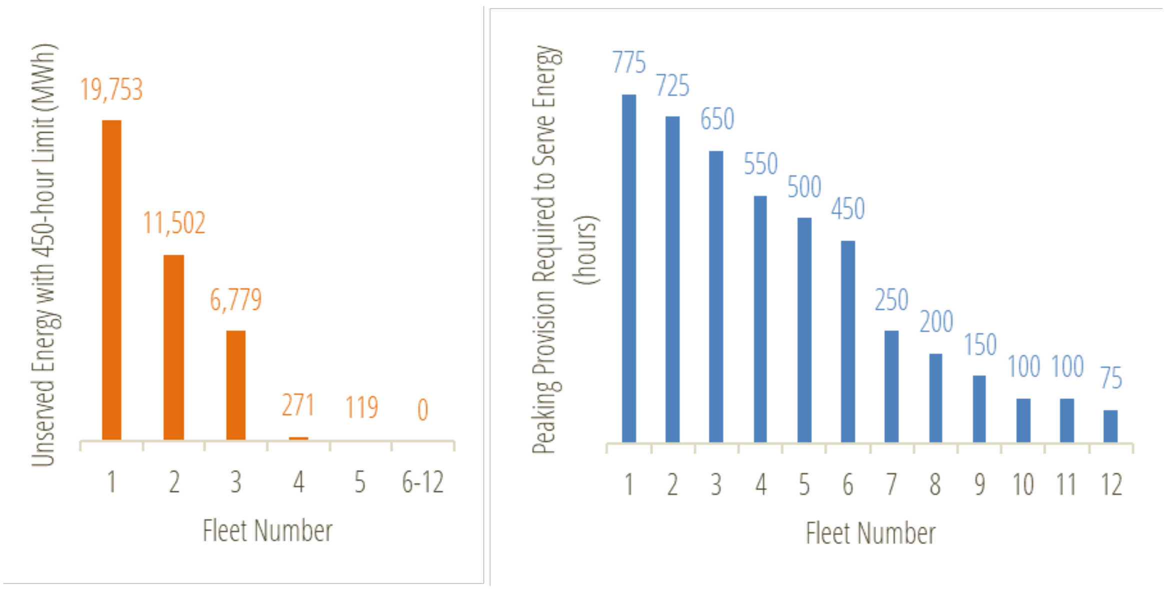

Figure 4. Results of peaking provision analysis in the worst-case scenario, annual totals for 2035

It is noteworthy that this result is partly accomplished by what is sometimes called an "overbuild" of zero-marginal-cost generation, particularly wind, so-called because the

[12] *Zeroing In,* 2.

[13] Canada Energy Regulator, *Canada's Energy Future 2023: Energy supply and demand projections to 2050,* (2023), 69. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/

[14] Stephen Thomas and Tom Green, *Shifting Power: Zero-Emissions Electricity Across Canada by 2035,* (David Suzuki Foundation, 2022), 41-44. https://davidsuzuki.org/science-learning-centre-article/shifting-power-zero-emissions-electricity-across-canada-by-2035/

[15] International Energy Agency, *World Energy Outlook 2023*, 17. https://www.iea.org/reports/world-energy-outlook-2023

[16] Notably, the model employed storage operation sequentially across all hours, charging and discharging the storage assets in an attempt to avoid unserved energy. The charge/discharge cycles are constrained by: wind/solar availability, battery charge capacity (MW), discharge capacity (MW), and energy capacity (MWh).

amount of $0/MWh-bid generation on the system is greater than system load in some hours. Some analysts and commentators see this as a negative and even hardwire their analysis against it, but because wind energy is so inexpensive, it can provide lowest-cost outcomes even with some curtailment. And, in a system with increasing levels of installed wind capacity, excess kinetic energy from the newer wind turbines could be used to provide synthetic inertia to mitigate frequency disturbance events.[17] At the same time, interties and more storage can help to create economic value from the excess energy. The key point is that the combination of storage with a strong compliment of wind will support supply adequacy even in the most challenging and lowest-wind hours.

C. Gas plant operations

Using hourly pool prices from the Pembina Institute and University of Alberta's research in *Zeroing In*, we can find the number of hours that a simple cycle natural gas plant would need to be dispatched to recover its costs.

Modelling assumptions

Table 1 outlines the parameters used to calculate the cost of operating a simple cycle natural gas plant in 2035 in this analysis.

Table 1. Summary of assumed simple cycle costs

Parameter	Value
Inputs	
Capital Cost ($/kW)	1,125
Weighted Average Cost of Capital (%)	10%
Operating Life (years)	20
Financing Cost ($/kW-year)	132

[17] In an electricity grid, the inertia of large rotating generators in conventional power plants can be used to smooth perturbations in grid voltage and frequency. Wind-driven synthetic inertia is not a new concept. In 2005, Hydro Quebec introduced a new mandate requiring all new wind turbines to be capable of providing this service, with the first being installed in 2011. By 2016, two-thirds of Quebec's wind capacity was made up of inertia-compliant turbines. (Peter Fairly, "Can Synthetic Inertia from Wind Power Stabilize Grids?" *IEEE Spectrum*, November 7, 2016. https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids)

Variable Operating Cost ($/kWh)	6
Fixed Operating Cost ($/kW-year)	20
Heat Rate (GJ/MWh)	10.3
Emissions Intensity (tCO_2e/MWh)	0.62
Natural Gas Price ($/GJ)	5.82
Carbon Price ($/$tCO_2e$)	170
TIER Benchmark for Electricity (tCO_2e/MWh)	0
Results	
Fixed Costs* ($/kW-year)	152
Variable Costs** ($/MWh)	171

* Fixed Costs include amortized capital costs and fixed operating costs
** Variable Costs include variable operating costs, fuel costs, and emission costs

Results

Table 2 outlines the number of hours that it would be economic for a newer simple cycle natural gas plant (one which is still making amortization payments) to operate under each scenario from *Zeroing In*, as well as the economic performance of that plant if it was dispatched during those hours.

Table 2. Economic performance of a simple cycle natural gas plant that is making amortization payments in a decarbonized electricity grid, 2035

Scenario	Number of economic operating hours*	Deficit if operated in those hours**	
		Energy ($/MWh)	Capacity ($/kW)
High Credit	826	210	95
Baseline	526	187	84
Increased Trade	365	207	93
High Storage	617	191	86
Near-Zero	469	244	110

Near-Zero+	695	208	93

* The number of hours that the electricity pool price is greater than the marginal operating cost of a simple cycle natural gas plant. Or, in other words, the number of hours that a simple cycle asset can earn more than it costs to operate.

** The difference between annual costs and revenues divided by total generation (left) or installed capacity (right)

Results of this analysis show that, under the current market design in Alberta, it may no longer be economic to operate a newer natural gas peaking plant in 2035, regardless of the regulated peaking exemption limit. Across all six scenarios, assuming a peaking plant is dispatched only during the hours that the pool price is higher than its operating costs, it would need an additional $187-244/MWh of energy revenue or $84-110/kW of capacity or reliability payments in order to cover its costs. Because the deployment of high levels of wind and storage with much lower marginal operating costs will limit the use of expensive gas peakers as a function of the market, this inadequate revenue would arise under the current market design *regardless of the CER's unabated peaker exemption limit.*

It is worth noting that this analysis assumes the peaker is still paying amortized capital costs, making it presumably less than 20 years old. In other words, the results presented in Table 2 are for a simple cycle natural gas plant that is not yet covered by the CER due to the EoPL provision. Even with the EoPL exemption, the plant is not economic — not because of the limited hours under the exemption, but because these scenarios have high levels of lower marginal operating cost generation. A weaker peaker exemption (higher number of hours) will not solve this.

We can perform the same analysis as above for a peaking plant that has accomplished its amortization by removing the $132/kW-year capital financing cost in the initial assumptions (Table 1). In this case, the plant would be limited to a maximum of 450 operating hours, as we assume that it is now outside the 20-year EoPL window. Table 3 outlines the economic performance of a time-constrained peaking plant in 2035, assuming it is no longer making amortization payments. Results of this analysis show that 450 hours of peaking operation is more than enough time for this type of plant to make an economic return in a 2035 Alberta electricity grid. In other words, despite their high marginal operating costs, there is sufficient revenue opportunity for existing natural gas peakers to operate under the current CER peaking provisions, even with Alberta's existing market design.

Table 3. Economic performance of a time-constrained simple cycle natural gas plant that is no longer making amortization payments in a decarbonized electricity grid, 2035

Scenario	Economics if operated for up to 450 hours		
	Costs ($/MWh)	Revenue ($/MWh)	Profit ($/MWh)
High Credit	216	418	202
Baseline	216	336	120
Increased Trade	216	287	71
High Storage	216	354	138
Near-Zero	216	270	54
Near-Zero+	216	367	151

Natural gas peakers will play an important, but limited, role in a net-zero grid. However, due to the unfavourable economics of simple cycle natural gas plants in an increasingly decarbonized electricity system, facilities that are still within their amortization period would require additional revenue streams in order to make a return on investment — again, regardless of the CER's unabated peaker exemption limit. In fact, the Alberta Electric System Operator is currently undertaking a Market Pathways Initiative that aims to address potential deficiencies — including the one highlighted above — of the existing market structure in Alberta.[18] On the other hand, existing peakers that are outside their amortization window — here, assumed as 20 years and thus ineligible for exemption under the EoPL provisions — would be able to make an economic return under a 450 hour operating limit. As such, this analysis indicates that any criticism that the 450-hour unabated peaker exemption limit is insufficient to allow peakers to recover fixed operating costs and remain available is misguided on two accounts:

1) It faults the exemption limit as the cause of the inadequate revenue, even though the changing supply mix will also result in the same effective outcome.

2) It assumes a market design that is in the process of being overhauled specifically to resolve this issue (and, indeed, that government officials have clearly said will be overhauled to ensure revenue adequacy for natural gas).

[18] Alberta Electric System Operator, "Market Pathways." https://www.aesoengage.aeso.ca/market-pathways