UNIVERSITY OF ALBERTA
FACULTY OF ARTS
Department of Economics

Working Paper No. 2024-03

Electricity Market Design with Increasing Renewable Generation: Lessons From Alberta

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Updated February 2025

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Abstract

The electricity sector is going through a period of rapid transition with increasing decarbonization through the growth of renewable energy. In this paper, we consider the case of Alberta which has observed considerable growth in wind and solar generation. We summarize the attributes of Alberta's simplified electricity market design and examine its challenges with increasing renewable output. We explore lessons from integrated market designs that account for the physical realities of the power system during market clearing, highlighting how this alternative market framework can help alleviate Alberta's challenges. We note how features of this market design can promote a more reliable and cost-effective grid with increasing renewable energy.

Keywords: Electricity Markets, Regulatory Policy, Renewables, Reliability

JEL Codes: L51, L94, Q28, Q48

*We thank Akshaya Jha, Gordon Leslie, Peter Reiss, and Frank Wolak for their numerous comments and suggestions. We acknowledge funding from the Canada First Research Excellence Fund as part of the University of Alberta's Future Energy Systems research initiative and the Social Sciences and Humanities Research Council's Canada Research Chairs program.

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1 Introduction

The electricity sector is undergoing a rapid transition worldwide. The growing reliance on renewable energy and the electrification of transportation and heating are transforming electricity systems. Renewable energy is projected to account for one-third of global generation by 2025 (IEA, 2024), with numerous jurisdictions setting ambitious net zero targets for the coming decades.[1] At the same time, peak electricity demand is expected to increase with rising temperatures and increasing electrification (Auffhammer et al., 2017; Mai et al., 2018; Rivers and Shaffer, 2020).

These changes are intensifying pressure on electricity sectors in jurisdictions transitioning away from fossil fuels. Historically, electricity markets were designed to operate with centralized dispatchable fossil-fuel resources. The increased variability in renewable generation often located further from load centers has created challenges for existing market designs. As conditions change, the electricity market design needs to evolve.

In this paper, we provide the context of Alberta's electricity market, one of the few remaining restructured markets that relies solely on revenues from wholesale energy and ancillary service markets to facilitate resource adequacy (often referred to as an "energy-only" market). In recent years, Alberta has experienced considerable growth of renewable energy resources and evolving environmental regulations. Between 2015 and 2024, renewable output from wind and solar resources increased from 5% to 17% of total supply. Over the same period, there has been a rapid decline in coal generation from 50% of output to only 2%, with coal completely leaving the market in the summer of 2024. Natural gas generation has also expanded, making up 78% of generation in 2024.[2] These market changes have come with significant reductions in emissions.[3]

As a relatively isolated northern climate, Alberta faces several key challenges with integrating renewable resources. In particular, Alberta has limited interties with neighboring Canadian provinces and the United States, extreme temperatures, and prolonged periods of low renewable output when demand is often highest (e.g., on extremely cold, windless, and dark winter days).

Alberta operates as a "simplified" (decentralized) market design, meaning it ab-

[1]Canada has an economy-wide net zero emissions target by 2050, with ongoing policies to accelerate the electricity sector towards net zero by 2035 (ECCC, 2023). More broadly, as of 2022, 68 countries and the European Union have pledged to various net zero targets (IEA, 2022).

[2]Data source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

[3]For example, the average estimated emissions intensity has fallen from 0.75tCO2e/MWh in the fourth quarter of 2017 to 0.43tCO2e/MWh in the fourth quarter of 2023 (MSA, 2023c).

stracts from many physical characteristics of the power system during wholesale market clearing. This market design makes achieving cost-effective and reliable renewable resource integration more challenging and is increasingly divergent from approaches taken in other jurisdictions with growing renewable capacity. Examples include the lack of day-ahead market mechanism with security constrained unit commitment and economic dispatch to account for system and generation unit constraints, a single province-wide price with no short-run congestion pricing signals, and an intra-provincial transmission policy that requires infrastructure build-out to ensure there is no congestion in the long-run. Another element that is particularly unique to Alberta is the stated view that unilateral market power execution in the wholesale market is part of the market design and necessary to achieve resource adequacy.

We describe how Alberta's market design features have interacted with the evolving generation mix and have led to ongoing operational challenges raising reliability concerns, questions over the viability of the existing transmission congestion management and investment approach, and long-running debates over market power and investment incentives. Alberta is currently undergoing a market redesign to address these challenges (AESO, 2024a). Rather than debate the merits of ongoing proposals that have yet to be finalized, we take a broader view. We highlight relevant market design features that merit consideration and draw lessons from both the academic literature and ongoing experiences in other jurisdictions.

We focus in particular on the principles of integrated (centralized) market designs implemented in restructured markets in the United States. These market designs include financially binding security-constrained day-ahead markets that account for the physical realities of the power system as part of market clearing. We summarize how the various features of these market designs can help mitigate the challenges currently facing Alberta. In addition, we discuss the role of locational marginal pricing that is core to these centralized market designs as an alternative to the current out-of-market re-dispatch mechanisms used to manage transmission congestion. Finally, we review the regulatory approach regarding market power execution and long-run resource adequacy and discuss how this impacts Alberta's market design going forward.

The paper proceeds as follows. Section 2 provides a background on the configuration and operation of Alberta's electricity market. Section 3 illustrates the considerable growth of renewable resources and summarizes key drivers. Section 4 describes the operational and market design challenges that have arisen together with the growth in renewables. Section 5 summarizes ongoing market reforms and presents key market design elements that can facilitate the integration of renewable generation, taking lessons from centralized market designs. Section 6 provides conclusions.

2 Alberta's Electricity Market: Background

Alberta's electricity market has operated as a competitive restructured wholesale market since 2001. In this market, generators only receive payments for providing electricity in a real-time wholesale energy market and an ancillary services market. This contrasts with many restructured markets that also provide capacity payments for making generation capacity available.[4] Alberta's market is what is often called a simplified or decentralized market design. As will be detailed below, the energy market clears abstracting from various physical features of the transmission network and generation unit constraints.

In Alberta's energy market, generators compete in a single hourly real-time uniform-priced auction. For each hour, firms submit up to seven price-quantity blocks for each generation unit that reflect the prices at which they are willing to supply electricity. Offer prices must fall between \$0/MWh and \$999.99/MWh. An administrative price cap of \$1,000/MWh applies during supply scarcity conditions.[5]

The Alberta Electric System Operator (AESO) – the organization that manages and operates Alberta's electricity market – dispatches energy market offers in order of least cost until there is sufficient supply to meet demand, setting the System Marginal Price (SMP). The pool price paid to all generators that supply output throughout the hour represents the time-weighted SMP. Units are simply called upon (dispatched) to supply output based on their bids in the real-time market and paid the hourly pool price.

There is a misalignment between the energy market settlement based on the pool price (hourly) and the time interval of dispatching that sets the individual SMPs (minute by minute). In some hours, because demand and market conditions vary throughout the hour, it is possible for a unit to receive a dispatch from the AESO, generate electricity and receive the pool price, but that hourly pool price falls below their offer price in the energy market. In this circumstance, generators receive uplift payments to keep them whole. These uplift payments arise outside of the hourly energy market.

Important for our subsequent discussions, there is no day-ahead market mechanism. Generators independently make their commitment decisions of when to turn

[4]For a detailed review of capacity mechanisms, see Holmberg and Tangerås (2023). Alberta began to pursue implementing a capacity market design in 2017 (Brown, 2018). However, the market reforms were terminated in 2019.

[5]All currency references in this paper are to Canadian dollars, unless otherwise noted. At the time of writing (January 2025), \$1 CAD $\approx$ \$0.69 USD.

on their assets (which can take several hours for certain generation units) and bid into the real-time energy market. This is often referred to as a *self-commitment* model. In addition, there is no security-constrained economic dispatch (SCED) that accounts for transmission system and unit constraints when the AESO calls upon units and determines the pool price paid to generators. As a result, there is no locational marginal pricing (LMP) on the transmission network that permits energy prices to vary by location to account for congestion (and losses). Further, Alberta has a "no congestion" policy where in the long run sufficient transmission capacity is to be constructed such that there is no congestion (Government of Alberta, 2023). When congestion arises in the short run, the single pool price is calculated as though congestion did not occur. Re-dispatching mechanisms are used to manage congestion when it arises. Congestion management will be discussed in detail in Section 4.2.

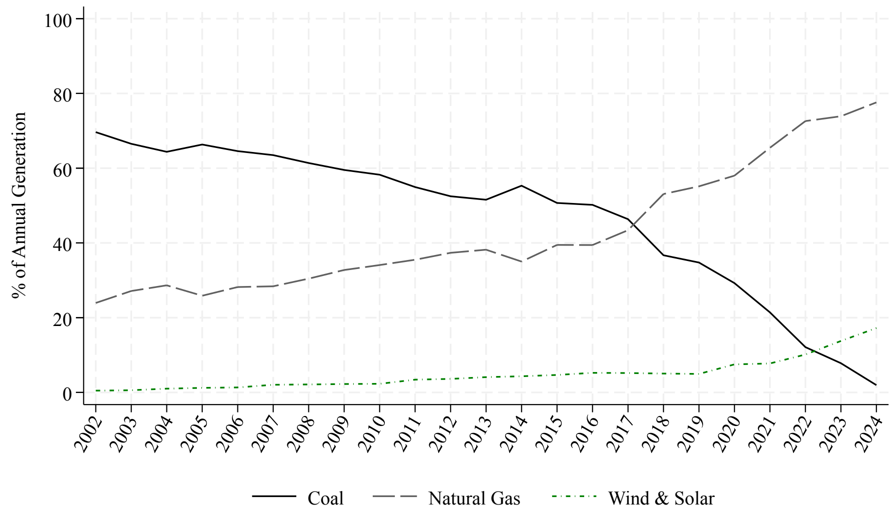
In addition to the wholesale energy market, the AESO procures several ancillary services (AS) products in a day-ahead market. These markets are cleared prior to the wholesale energy market (i.e., the AS market is not co-optimized with the wholesale market). The AS market prices are indexed to the subsequent market-clearing pool price (reflecting premiums above the pool price). AS products are used to balance supply and demand, accounting for typical real-time variability (e.g., variability in supply and demand) and unexpected events (e.g., unit outages). For certain AS products, a commitment to supply AS precludes them from offering this capacity into the energy market. AS procurement costs are passed through to end users (load) as part of their transmission tariff.

Alberta's market is relatively small and isolated from neighboring jurisdictions. For example, in 2022 the average wholesale demand was 9,883 MW with a peak of 12,193 MW that occurred in the winter. Alberta has approximately 1,100 MW of transmission import capability with neighboring jurisdictions British Columbia, Saskatchewan, and Montana.[6] Net imports cover approximately 5% of Alberta's electricity usage (AESO, 2022a).

The generation mix consists largely of fossil-fueled generation. Figure 1 presents the percentage of annual generation supplied by coal, natural gas, and wind and solar generators from 2002 - 2024. Over this period, we observe a rapid decline in coal output and an increase in natural gas generation. Between 2015 and 2024, coal generation fell from approximately 50% of total generation to less than 2%, while gas increased from 40% to 78%. Over the same period, wind and solar output increased from approximately 5% to 17% of total generation, with the majority of this output

[6] Based on the average system import capability for 2023 using data from the AESO's ATC Public Report.

Figure 1. Annual Generation - Coal, Natural Gas, Wind & Solar



Source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

being supplied from wind facilities.

The configuration of Alberta's electricity demand is unique in that approximately 80% is non-residential, with 47% coming from industrial customers (AUC, 2024a). This compares to the United States in which 64% is non-residential and 26% is industrial (EIA, 2024). A sizable portion of Alberta's generation capacity comes in the form of cogeneration that produce electricity as a by-product of an industrial process.[7]

Another unique aspect of Alberta's market design is its market concentration and views on market power. Alberta's market has undergone periods of moderate market concentration. For example, in 2022 four firms had offer control over 56% of installed capacity.[8] Unilateral market power in the energy market in the form of economic withholding – the bidding of generation units in excess of marginal cost – is viewed as an element of the market design rather than behavior that is to be explicitly restrained (MSA, 2011, 2020).[9] The primary argument for this regulatory framework is to facilitate fixed cost recovery of generation units in the absence of capacity payments. Alberta's often called "energy-only" market design takes the stance that entry and market competition will discipline the market. Brown and Olmstead (2017) and Brown et al. (2023) show that there have been periods of elevated economic with-

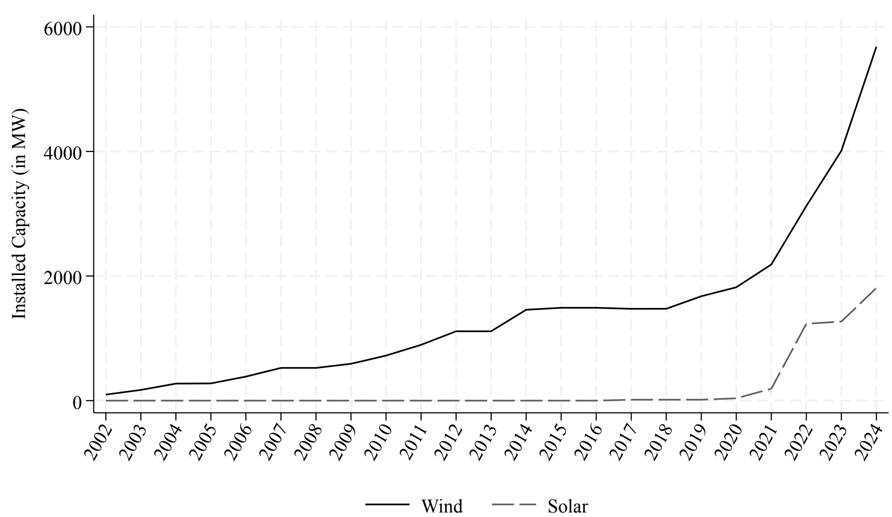
[7]For example, in 2020, 34% of total generation capacity came in the form of cogeneration facilities (AUC, 2024b).
[8]Source: Alberta MSA's Market Share Offer Control report available at albertamsa.ca/documents/reports/msoc/.
[9]Alberta's Market Surveillance Administrator (MSA) is the independent market monitor of Alberta's electricity market that is tasked with ensuring market participants comply with legislation and the AESO's rules.

holding leading to a trade-off between short-run inefficiencies and the promotion of long-run investment. While firms can employ economic withholding, physically withholding available generation capacity is not viewed as acceptable and may be subject to *ex-post* enforcement. As will be discussed below in Section 4.1, concerns over physical withholding can arise under existing AESO rules by generation units that take several hours to start up (referred to as "long-lead time" units). This has led to short-run operational concerns setting off calls for market reforms.

3 Growth of Renewable Generation

While renewable output remains a relatively modest percentage of total electricity generation in Alberta, as seen in Figure 1, the construction of renewable generation capacity has been increasing rapidly in recent years. Figure 2 presents installed utility-scale wind and solar capacity (in MW) over 2002 - 2024. There has been a sizable increase in the rate of wind and solar capacity additions starting in 2020. As of 2024, there are 5,680 MW of wind and 1,808 MW of solar capacity installed. This reflects approximately 35% of installed system capacity, increasing from just 1,491 MW (9%) in 2015.[10]

Figure 2. Installed Generation Capacity of Wind and Solar



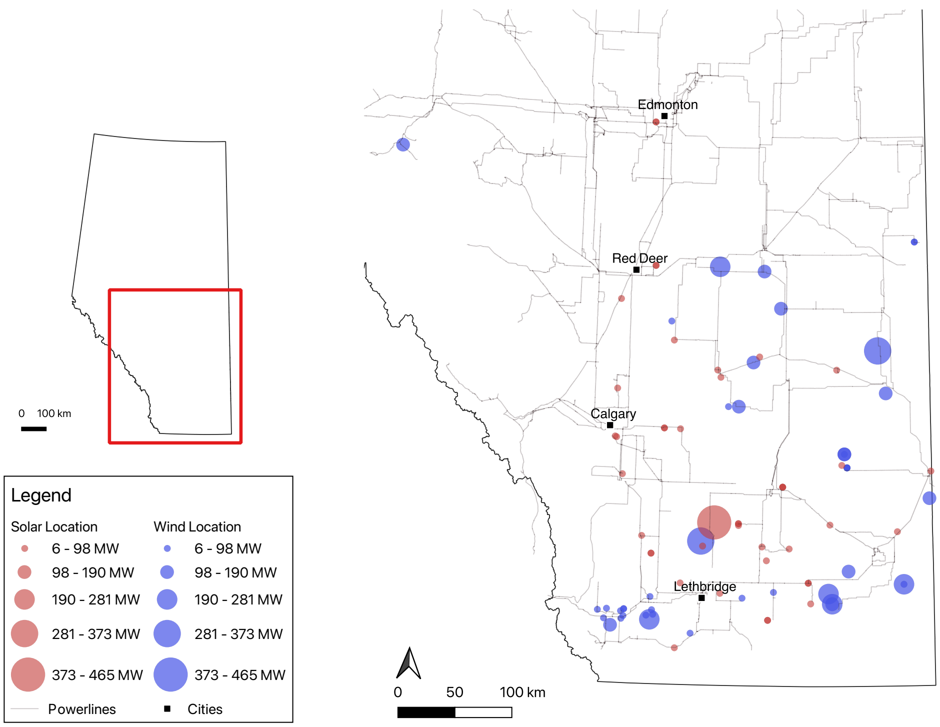
Source: Alberta Utilities Commission Annual Electricity Data available at auc.ab.ca/annual-electricity-data/.

In August 2023, the Government of Alberta announced a moratorium on renewable

[10]There is also an increasing amount of behind-the-meter microgeneration in the form of solar PV. As of December 2023, there is 207 MW of solar at over 17,500 customer sites in the province (AESO, 2024c).

projects exceeding 1 MW and directed the Alberta Utilities Commission to review the policies around renewable development. In February 2024, the Government announced new policies with restrictions on the development of agricultural land, and requirements around end-of-life reclamation costs, among other factors related to the review and approval of future projects (Government of Alberta, 2024b). While outside the scope of this discussion, these policy changes are expected to adversely affect future renewable development.[11]

Figure 3. Location of Installed Wind and Solar Facilities



Source: Alberta Market Surveillance Administrator.

Figure 3 presents a map of the wind and solar generation resources installed and operating in the province, along with the four largest cities.[12] Wind and solar facilities are concentrated in the southern and eastern regions of the province. For both technologies, the resource endowments are highest in these regions. The largest city centers in the province are in Calgary and Edmonton with populations of approximately 1.3 and 1.1 million, respectively, followed by Red Deer and Lethbridge with populations of approximately 100,000 and 90,000.

As shown in Figure 3, the emerging wind and solar facilities are located far outside

[11] For a detailed discussion of the renewable development restrictions, see Luo (2024).
[12] Generator locations collected by Authors. Transmission lines are available at Open Infrastructure Map https://openinframap.org/.

of the two largest cities. In addition, large industrial load centers are located in the northern parts of the province (not shown in this image). A large number of these facilities have co-located cogeneration units to meet on-site demand. As will be discussed in Section 4, the geographical concentration of wind and solar creates challenges due to the temporal and spatial correlation of renewable output, combined with the costs of building transmission lines to connect these generators to the load centers.

It is informative to summarize the key economic and policy drivers that have led to the rapid increase in renewable generation investment, the collapse of coal generation, and the increase in natural gas production documented above. The drivers are primarily associated with environmental policies and low natural gas prices rather than the wholesale market design, but they have implications for its operation. Alberta has had a policy to price carbon emissions since 2007.[13] The original policy, the *Specified Gas Emitters Regulation* (SGER), applied to large generation facilities. Under SGER, generators had a facility-specific benchmark starting at 88% of the facility's historic emissions level. If a generation facility produced more than this benchmark, it would have to purchase offset credits or pay a carbon price of $15 per tCO2e for these excess emissions. In 2016 and 2017, the stringency of both the facility-specific benchmark and fee per tCO2e ratcheted upwards. However, the design of and parameters for the facility-specific benchmark resulted in relatively modest costs of compliance in 2017, with a cost of $6/MWh for coal generators and even lower costs for gas-fired units.

In 2018, Alberta changed its carbon pricing policy through a broader carbon pricing mechanism initially named the Carbon Competitiveness Incentive Regulation (CCIR), renamed the Technology Innovation and Emissions Reduction Regulation (TIER) in 2020. For the electricity sector, the CCIR/TIER policy moved away from SGER's facility-specific benchmarks, establishing a sector-wide emissions intensity standard of 0.37 tCO2e/MWh faced by all generators. This standard was based on a deemed "best-in-class" combined cycle natural gas generator at the time.[14] Generators above this benchmark must pay the carbon price for the difference between their emissions intensity and the benchmark. The carbon price was set by the Government of Canada to be $30/tCO2e for 2018, 2019, and 2020, and $40/tCO2e in 2021, $50/tCO2e in 2022, and then increase by $15 each year until hitting $170/tCO2e in 2030.

The change to the CCIR/TIER framework in 2018 led to a sizable escalation in

[13] For a more detailed discussion of carbon pricing in Alberta, see Leach (2012) and Olmstead and Yatchew (2022).

[14] The sector-wide emissions intensity standard of 0.37 tCO2e/MWh is expected to decline and reach 0 by 2035 (AESO, 2022b).

the cost of environmental compliance for coal generation, from \$6/MWh in 2017 to \$18.90/MWh in 2018, with further escalating costs as the carbon price increases. These marginal environmental costs translate to an increase in the short-run marginal costs of coal plants. Natural gas generators that are closer to the emissions intensity benchmark had considerably smaller costs of compliance (e.g., in the range of \$5/MWh for a simple cycle unit). In fact, the compliance cost for certain efficient combined cycle gas units actually fell under CCIR/TIER as compared to SGER.

The change to sector-wide benchmarks led to a reordering of coal and natural gas units, with gas units often offering lower prices in the wholesale market. Corresponding with this change in 2018, as can be seen in Figure 1, there has been a substantial reduction in both coal generation and capacity and increasing use of natural gas (Olmstead and Yatchew, 2022). In fact, in the summer of 2024, the final coal units were converted to gas-fired facilities, 6 years ahead of the government's target to phase out coal by 2030 (Scace, 2024).

The carbon pricing regime has implications for the economics of renewable generation. Under the CCIR/TIER carbon pricing policy, all generators below the 0.37 tCO2e/MWh benchmark receive value in the form of emissions performance credits (EPCs). For example, a zero-emission generator would receive 0.37 tonnes of EPCs for each MWh produced; these can be sold to other emitters in lieu of their compliance payments at the prevailing carbon price, e.g. \$40/tCO2 in 2021.[15] The value of EPCs are expected to increase as the carbon price increases (e.g., to \$170/tCO2e in 2030). The receipt of EPCs for the zero-emissions attributes of renewables are in addition to the payments earned when supplying power in the wholesale market.

In an effort to accelerate renewable deployment in the province, the Government of Alberta held a series of auctions in 2017 under the Renewable Electricity Program (REP). These competitive auctions led to the procurement of 1,360 MW of new wind generation capacity. Wind resources constructed as a result of these government-backed contracts secured a guaranteed fixed price per MWh for 20 years under a contracts-for-differences payment structure.[16] Combined with a decline in the cost of renewable generation worldwide, these economic forces and government policy initiatives contributed to the increase in renewable generation investment in the province.

[15] Renewable generators remain eligible for a higher rate of 0.52 tCO2e/MWh in 2021 under a pre-existing Alberta Emission Offset Program. This higher rate is set to decline and equal the TIER rate in 2030.

[16] Hastings-Simon et al. (2022) provide a comprehensive discussion of Alberta's REP.

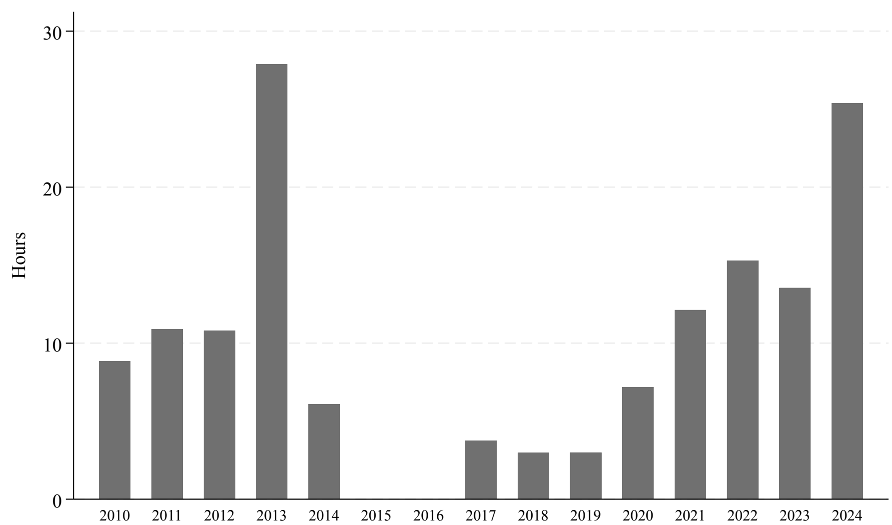
4 Impacts on the Market

In this section, we describe the key market design challenges that have arisen or been magnified as renewable generation has grown. This has amplified the inefficiencies that result from Alberta's simplified market design and transmission management policies. Our primary focus will be on the growing short-run operational and reliability challenges, as well as the increasing concerns over transmission congestion and its management.

4.1 Short-Run Operational and Reliability Challenges

Energy Emergency Alert (EEA) events are issued when the power system is approaching supply shortfall conditions and are a measure of when the power system is at greatest risk of involuntary load shedding, i.e., brownouts. Figure 4 presents the duration of EEA events from 2010 to 2024. From 2010 to 2014, EEA events were largely related to forced outages of thermal generators during periods of high demand. From 2017 onward, EEA events have occurred when the power system was stressed due to combinations of high demand, low wind generation, over-forecasting of wind and solar generation, thermal generation outages, and reduced import capability.[17]

Figure 4. Energy Emergency Alert Events, hours per year



Source: Market Surveillance Administrator.

While there is sufficient natural gas-fired generation capacity (assuming there are

[17] For a detailed discussion of recent EEA events and their causes, see MSA (2024a,b). The elevated EEA events in 2013 are discussed in MSA (2013).

sufficiently few outages) to meet demand without wind or solar generation, some of this capacity has a high marginal cost, incurs large start up costs, and can take up to a full day to start up. These units are referred to as long lead time (LLT) assets. Cost characteristics mean that it is generally not profitable for LLT units to be kept online all of the time – especially when wind or solar generation levels are high or, perhaps more importantly, expected to be high.[18]

In the prevailing market design, generators employ self-commitment based on their expectations of future market conditions and receive no cost guarantee in the hourly real-time market. Rather, generators form expectations on whether they can recover both their dynamic costs associated with starting up their unit and the marginal cost of operating via the hourly pool price. This decision is becoming increasingly challenging as uncertainty and variability in the system increase over the timeline of the unit commitment decision in the presence of growing renewable output (Jha and Leslie, 2025). There have been instances where LLT assets chose not to commit their unit and bid into the real-time energy market, only for realized market prices and supply conditions to later indicate the need for this generation. In particular, there have been documented cases where the market operations would have triggered a reliability event if a single generator tripped or renewable generation did not over-perform relative to its forecast (MSA, 2023b). As a consequence, there are growing concerns over the unit commitment decisions and how this interacts with Alberta's simplified wholesale market design.[19]

As a practical matter, because generators can make their own independent unit commitment decisions, it is difficult to distinguish instances in which firms do not start up a generation unit because they do not expect it to be profitable versus when they are exercising market power in a form of physical withholding. While there are rules against physical withholding, the AESO rules permit generators to make their own unit commitment decisions.[20] This has raised concerns that market power execution in the form of physical withholding of LLT units could potentially be taking place and lead to short-term reliability challenges (MSA, 2023a).

Looking forward, to facilitate short-term reliability, a key issue will be to ensure that there is sufficient dispatchable generation capacity committed to be able to supply power when it is needed. This becomes increasingly important as more variable

[18]In 2023, for the first time, there were times when wind and solar generation exceeded 50 percent of system demand, i.e., total electricity consumption less production by on-site generation capacity (MSA, 2023c).

[19]In addition to unit commitment challenges, there have been increasing instances of frequency events that arise when there are outages of large generation units and/or transmission interties with neighboring jurisdictions. The growth in renewables and decline of synchronous thermal resources has led to a reduction in the inertia on the system. While this is an important issue, a detailed discussion is out of the scope of the current article. For a related discussion, see MSA (2024c).

[20]For details on the rules around managing LLT units, see page 35 of MSA (2023b).

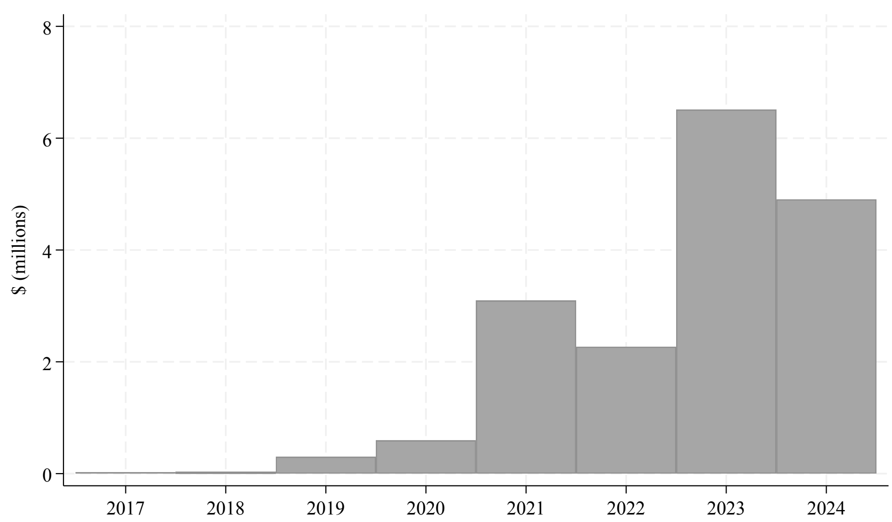
renewable resources are deployed in the province. Many markets worldwide have implemented day-ahead markets with security-constrained unit commitment mechanisms to help achieve these objectives. Section 5.2 will provide a detailed discussion of these day-ahead market designs.

4.2 Transmission Congestion Management

Figure 5 plots the annual costs of managing transmission congestion between 2017 - 2024. Historically, congestion has been relatively rare. As noted in Section 2, transmission investment is planned by the AESO to meet a “no congestion” standard; minimal congestion has been a policy decision. Figure 5 demonstrates that there has been a considerable increase in congestion management costs in recent years. This coincides with an increase in outflow constraints due to transmission limits connecting increasing wind and solar generation to load centers (recall Figure 3). In 2023, 286 GWh of wind and solar generation was curtailed. This represents a 445% increase from 2022, which had only 53 GWh of wind and solar curtailment (MSA, 2023c).

Despite the increase in congestion costs in recent years, it remains relatively modest. For example, the AESO’s Transmission Operating Cost budget in 2023 was approximately $2.4 billion (AESO, 2023). While congestion costs have been low historically, there are concerns that these costs could continue to increase in the future, particularly if there is a change in the “no congestion” transmission investment policy.

Figure 5. Annual Congestion Costs by Year



Source: AESO.

Transmission congestion is not considered when setting the real-time pool price that is applied uniformly across the province. Congestion can either reflect an inflow or outflow constraint. Renewable growth has led to an increase in outflow constraints. When an outflow constraint occurs, there is insufficient transmission capability to deliver all generation that has cleared the energy market to the grid. In this setting, the AESO identifies assets that can be curtailed on the upstream side of the constraint. For the first two hours, the constrained-down assets are curtailed and selected based on their offers in the energy market, taking the highest offers first. After two hours, assets behind the constraint are curtailed pro rata.[21] Constrained-down units do not receive payments.

To meet the required demand, the AESO identifies assets that can be constrained-on downstream of the constraint. These units are selected based on the lowest-priced offers in the energy market. Because their offers exceed the price of the unit setting the market-clearing energy price (i.e., the uncongested price), constrained-on units are paid-as-bid. The payments above the pool price are provided as an out-of-market uplift. These costs are charged to loads through a volumetric usage charge. The units that are neither constrained-on nor constrained-off are paid the uncongested pool price.[22]

Generators are aware of the presence of congestion and the incentives that arise during the re-dispatch process. This can create scope for strategic behavior and reduced short-term operational efficiency. For example, a generator that knows it will be dispatched on and paid-as-bid will have an incentive to elevate its bid. While this behavior has been limited in Alberta in part because congestion has been minimal historically, these challenges have arisen in other jurisdictions with zonal markets that have similar re-dispatch mechanisms to alleviate congestion. In particular, there is a large literature documenting this type of behavior and the associated inefficiencies with this market design (Katzen and Leslie, 2024; Eicke and Schittekatte, 2022). Graf et al. (2021b) provide evidence from Italy to show that the challenges associated with re-dispatch increase as renewable generation expands.

In the presence of a single province-wide energy price, there is no location-specific signal within the energy price. This has the potential to distort the location choices of generators, including renewable resources that thus have the incentive to locate to maximize total output rather than choose a site based on its location-specific energy

[21]Because renewables systematically bid in at a price of \$0/MWh, and Alberta has a price floor of \$0, when renewable output is the primary driver of the constraint, these units are curtailed pro-rata to alleviate the constraint. The distinction where units are selected based on their bids for the first two hours could play a more important role in this setting if negative pricing were permitted.

[22]For additional discussion of congestion management in Alberta, see Olmstead and Yatchew (2022) and AESO (2024b).

value. Alberta currently has a static location signal via its Generating Unit Owner's Contribution (GUOC). The GUOC requires generators to pay a price per MW of capacity (e.g., $30,000/MW) for locating at different regions of the province. This location-specific fixed charge is broad, dividing the province into only six fixed regions. The GUOC has a maximum charge of $50,000/MW and the charge is refunded over a 10-year period as the unit generates electricity (Government of Alberta, 2023). The goal of the GUOC is to motivate generators to locate near existing transmission infrastructure and follow through with investments. However, the ceiling on the GUOC charge (and its refundable nature) mute its financial implications. In addition, by setting the GUOC based on a fixed capacity charge that is defined across broad regions and remains static over time (i.e., it does not vary hourly), this mechanism does not send a sufficiently granular signal of the temporal or spatial value of energy.

Finally, geographically concentrated renewable capacity interacts with the prevailing transmission planning policy. Transmission investment is planned by the AESO to meet a "no congestion" standard. This requires sufficient capacity to provide "reasonable access" to all in-merit generation when no transmission is out-of-service. Transmission costs are passed almost entirely through to end consumers, raising concerns that keeping the status quo will lead to even further increases in transmission costs, an issue that has raised considerable debate in recent years due to rising transmission costs (Government of Alberta, 2023). If this policy were to remain in effect, transmission expansion would be needed in regions with growing wind and solar resources. However, this has raised increasing concerns over the relative cost and benefits of such transmission capacity expansion because of the significant cost and the geographical concentration of renewable resources resulting in a reduced market value of this energy. The transmission investment policy is outside of the scope of the AESO's market design as it is a choice of government policy rather than market design. However, the decision will have important interactions with the wholesale market design through its impact on the degree of congestion that will be permitted going forward.

5 Path Forward: Market Reforms

In this section, we discuss key market reforms that can alleviate the increasing challenges created by the growth in renewable generation and its interactions with Alberta's current simplified market design. We begin by summarizing recent interim market reforms and directions outlined by the Government of Alberta to address the growing operational challenges. We then describe approaches taken in other jurisdictions that have more sophisticated market designs that better account for the physical realities of the electricity system in market clearing. We discuss how the proposed direction of Alberta's market design fits within these alternative market frameworks.

5.1 Interim Reforms and Policy Direction

In response to the operational issues discussed in this paper, as well as affordability concerns related to high wholesale prices in 2022 and 2023 due to elevated market power, in the summer of 2023, the Government of Alberta (Government) directed the AESO and the MSA to provide advice related to potential market design changes. The AESO recommended the development of a Restructured Energy Market (REM) that would adapt the current market design to include features common to other restructured electricity markets, including a day-ahead market and improved real-time system operation tools (AESO, 2024a). The MSA made a similar recommendation and also recommended the implementation of several interim market reforms until the REM could be developed and implemented (MSA, 2023a).

One key proposed interim reform considers the unit commitment decisions of LLT units. The reform permits the AESO to direct generators on LLT status online when forward-looking (forecasted) supply-demand conditions are sufficiently tight. Committed generators are eligible for cost guarantees under some circumstances. This is a deviation from the historical self-dispatch framework as it provides revenue certainty to LLT units if they cannot recover their full operating costs after starting up. This ad hoc approach aims to reduce the reliability concerns of LLT units until (ideally) a more sophisticated mechanism is deployed. In addition, the interim reforms proposed a market power mitigation framework that serves as a "safety valve" to limit what is deemed to be excessive market power. Market power will be discussed in more detail in Section 5.3. On March 11, 2024, the Government announced that the interim unit commitment process (and market power mitigation rules) would be implemented on July 1, 2024 (Government of Alberta, 2024a).

In July 2024, the Government outlined the core market design elements for the REM in a direction letter to the AESO that included the following: (i) a mandatory day-ahead market; (ii) a requirement to maintain a single province-wide energy price; (iii) use of security constrained economic dispatch; (iv) co-optimization of energy and ancillary services, (v) shorter settlement intervals; (vi) consider lowering the price floor to permit negative pricing; (vii) a stated view that economic withholding is part of the core market design, but needs to be subject to oversight to avoid "excessive exercise of market power". The direction letter also indicated a key policy change that moves away from the no congestion planning standard to one that considers "optimal planned transmission".[23]

At the time of writing (January 2025), the REM consultations are ongoing. Rather than delving into specific details of the ongoing market design discussions, we take a broader view in the subsequent sections. We outline experiences in market designs from other jurisdictions and their relative merits in alleviating the challenges associated with integrating increasing renewables in a reliable and cost-effective manner. We highlight where the Government's direction does (and does not) facilitate the adoption of these market mechanisms.

5.2 Integrated (Centralized) Markets

The discussion above highlights two key challenges for short-term operations in Alberta. First, there is no coordinating mechanism to help facilitate unit commitment decisions. Second, real-time operating constraints (i.e., the physical realities of the system) are not fully considered when calling upon assets in the real-time energy market leading to the need for an out-of-market re-dispatch process.

Market designs, in particular in the United States, have developed market mechanisms for over two decades to address these operational issues. The restructured electricity markets in the US have all taken on what is often called an integrated or centralized market design. While the design elements vary across jurisdictions, there are several key principles that broadly apply.[24]

The system operator runs a multi-settlement market, with a day-ahead and real-time market. The day-ahead market (DAM) is a forward-looking *financial* market in which both the generation and demand-side submit bids. The market employs security-constrained dispatch in that the system operator co-optimizes the system to minimize the as-bid cost of supply to meet bid-in demand at all locations for the following day, considering the relevant transmission network constraints, generation unit constraints, and the need to also procure ancillary services. While this market is financial, if the DAM matched real-time market conditions, the DAM unit-level schedules could be dispatched to meet real-time demand at the right locations on the network. That is, it is physically feasible. In reality, the DAM does not perfectly match real-time conditions (e.g., due to changes in demand, renewable output, etc.). There is a subsequent real-time market (RTM) that determines prices of the deviations

[23]The direction letter can be accessed here: www.aesoengage.aeso.ca/42905/widgets/185854/documents/134459.

[24]For an extensive discussion of US market designs, see Helman et al. (2008), Ahlqvist et al. (2022), and Graf (2024).

from the DAM schedule. The RTM is also cleared through a security-constrained economic dispatch (SCED) that accounts for constraints on the transmission network and generation units using offers to determine market prices. Unlike the DAM, the RTM represents a physical commitment with dispatch instructions and takes the unit commitment of generators on the system as given.

Generators can submit "complex" bids that include volumetric (\$/MWh) and start-up (\$) components, along with other operational constraints and costs. Negative volumetric bids are permitted to facilitate efficient curtailment in the presence of excess supply. Start up and commitment-related costs are considered within the DAM. As a result, the DAM facilitates cost-minimizing unit commitment (based on bid-in costs) by specifying which generation units should be turned on in the DAM-clearing schedule. A multi-part offer that clears the auction comes with a "revenue sufficiency guarantee". If market revenues do not cover the full cost of operating, units are provided out-of-market "uplift" payments. This approach is employed to incentivize units to follow the schedules determined in the DAM. The inclusion of complex bids, unit commitment, and uplift payments dispatched in advance of real-time to co-optimize the system would help mitigate the LLT challenges facing Alberta. In particular, these features would reduce the uncertainty faced by these resources in advance of their unit commitment decisions.

Despite the fact that the DAM is not a physical commitment/dispatch schedule, there is an inherent financial incentive to follow the DAM schedule. For example, suppose a generator under delivers from its DAM schedule by 200 MW and there is scarcity on the system with a RTM price of \$1,000/MWh (Alberta's current price cap), when under delivery would be of most concern. The requirement to buy back any under-delivery exposes the generator to a financial loss to the extent the RTM price exceeds that of the DAM. If this under-delivery results from not turning on an LLT unit and scarcity conditions persist, it could face this financial exposure for several hours. The financial risk of under-delivery would be further magnified if the price-cap increases, as is being proposed, to \$3,000/MWh (AESO, 2024b). Because of the financial incentives and the fact that the DAM schedule is physically feasible by construction, most accepted DAM bids go on to physical delivery (Helman et al., 2008).

As part of the co-optimization of the system in an integrated market, the DAM and RTM produce locational marginal prices (LMPs), or "nodal" pricing. LMPs reflect the marginal value of energy, congestion, and losses at different locations of the network where energy is delivered or received. Unlike the re-dispatch process summarized in Section 4.2, the cost of delivering energy at different points in the network is reflected in wholesale energy prices. Generators compete in the DAM and RTM to supply energy at the expected locational price, while simultaneously satisfying the required network constraints (no re-dispatching process is needed). The seminal work of Schweppe et al. (1988) demonstrates the value of nodal pricing over less granular pricing. There is a growing empirical literature quantifying the wholesale price and operational benefits of moving to a nodal pricing structure (Zarnikau et al., 2014; Triolo and Wolak, 2022).

The relevance of moving to a nodal pricing system will be more acute in Alberta moving forward based on the Government's proposed changes to the transmission regulation policy with its movement away from the no congestion policy. This indicates that congestion would become a long-term element of the market, magnifying the value of efficient congestion management.

Taken together, integrated market designs aim to incorporate both the economic and physical realities of the system in a competitive market-based design. The DAM enables the system operator to pre-schedule generation, facilitate unit commitment, and provide a financial mechanism for generators and demand-side participants to hedge against volatile real-time conditions.[25]

This market design satisfies many of the elements outlined in the Government's direction letter in July 2024. This includes a DAM, considers co-optimization of energy and ancillary services, can be coupled with shorter settlement intervals, and leverages SCED to determine generation unit schedules.[26] Where this market design does not directly satisfy the policy direction is the requirement for a single province-wide energy price. A core element of the integrated market designs is the pricing of location-specific value of energy via LMPs. However, jurisdictions in the US do not charge the majority of retail customers their local nodal price due to the political challenges of charging certain customers more for being located near certain nodes. Rather, loads are often exposed to a weighted average of nodal prices across their region (Eicke and Schittekatte, 2022). In the extreme, in Singapore, generators are paid the LMPs at their location, but loads purchase wholesale electricity at the "Uniform Singapore Electricity Price" equal to the quantity-weighted average of the LMPs across the country (Wolak, 2021). Effectively, there is a single price for loads,

[25] In practice, there can be a systematic divergence between DAM and RTM prices and concerns over forward market liquidity. To tackle this, many US markets permit virtual bidding – the participation of purely financial entities. The empirical literature has found that virtual bidding reduces price spreads across these markets and limits market power opportunities (Mercadal, 2022; Jha and Wolak, 2023).

[26] Jurisdictions worldwide have transitioned towards more granular settlement periods, moving from hourly to 15 and even 5-minute settlement intervals (IRENA, 2019). Empirical evidence indicates that this can improve price signals to better reflect the value of energy, create stronger incentives for fast-start resources to better integrate renewable resources, and reduce overall wholesale prices (AESO, 2018; Märkle-Huß et al., 2018; Newbery et al., 2018).

but the operational benefits of LMPs for generation are captured.

We would be remiss if we did not discuss an alternative market design that is employed in most European markets, the often-called decentralized (or simplified) market design. Broadly speaking, decentralized markets also entail multi-settlement with a financial DAM and a physical RTM. This captures some of the benefits of providing a pre-planning opportunity for the system operator and hedging opportunities for market participants. However, unlike the centralized market framework, the decentralized DAM does not fully account for the physical realities of the transmission network and generation unit constraints when it clears. There is often no revenue sufficiency guarantee associated with the unit commitment costs. Rather, generators self-commit their units at a specific location on the network and are tasked with meeting this commitment. Congestion is considered across broader zones, but re-dispatch mechanisms similar to Alberta's current congestion management approach are used to manage intra-zonal congestion. As discussed in Section 4.2, these re-dispatch mechanisms can create additional complications and inefficiencies in matching DAM schedules to real-time constraints. There is growing evidence that as renewables expand, the consequences of misaligning the DAM and real-time operational constraints will become more severe (Graf et al., 2021b). These challenges can be seen in the ongoing debates over how to manage congestion in zonal markets in Europe with increasing renewable generation (Eicke and Schittekatte, 2022).

We end this section by acknowledging that a centralized market design does not come without its own challenges, including the computational complexity of solving the DAM and RTM co-optimization and the use of out-of-market uplifts to facilitate unit commitment. There are ongoing efforts to manage these challenges, including the development of alternative pricing mechanisms to incorporate uplift costs associated with managing dynamic (non-convex) costs within the LMPs (Liberopoulos and Andrianesis, 2016). Despite these challenges, there is a growing empirical literature documenting improvements in short-term operations as centralized market design elements are adopted (Wolak, 2011; Zarnikau et al., 2014; Triolo and Wolak, 2022). For a comprehensive review of centralized versus decentralized market designs, see Ahlqvist et al. (2022) and Graf (2024).

5.3 Market Power and Resource Adequacy

Alberta's regulatory environment has taken a unique view on market power compared to other restructured markets worldwide. This can be seen in the Government's July 2024 direction letter that explicitly stated the requirement that market power is to continue to play a role in the market. Within Alberta, the fundamental argument that is made is that market power is necessary to promote investment in generation capacity to facilitate resource adequacy.

We first note that market power is not a pre-condition to ensure resource adequacy. There is a large economics literature that demonstrates optimal investment can be achieved under what we will refer to as "full-strength" energy pricing (Borenstein, 2000; Joskow and Léautier, 2021). Essentially, these models require that the pool price is permitted to rise to a sufficiently high level (to the value of lost load) under system scarcity.

Limited demand-side participation, high cost of storage, and presence of concentrated markets yield conditions that are ripe for market power in the electric sector. There is a large literature documenting the presence of market power and the resulting short-run inefficiencies in the electricity sector (Borenstein et al., 2002; Jha and Leslie, 2025; Graf et al., 2021b), including work in Alberta (Brown and Olmstead, 2017; Brown et al., 2023). Alberta experienced a considerable increase in market power in recent years driven by an increase in market concentration.[27] The elevated wholesale prices (that are passed down to retail customers) have led to growing criticisms of the market design.

Market power can only be mitigated in restructured markets, not completely eliminated. This has led regulators to implement wholesale energy price caps to limit politically challenging price spikes and the scope for short-run rents, such as Alberta's $1,000/MWh price cap. However, low price caps are core to the resource adequacy problems, through what is often referred to as the "missing money" problem (Joskow, 2008), or more fundamentally the "reliability externality" (Wolak, 2021, 2022). This raises concerns that the wholesale market will not provide sufficient revenue to promote capacity investment. This has led to the view within Alberta that the market design will accept unilateral market power in the short run and the associated inefficiencies in order to provide short-run profits to promote long-run investment.

So what can be done within the electricity market design to simultaneously manage market power and promote resource adequacy? One of the core challenges facing electricity market design is the lack of demand-side participation resulting in highly inelastic demand. This has been a core driver of generator market power and the deployment of administrative price caps. Within centralized multi-settlement market designs, a key design element is the participation of the demand side. Demand is

[27]There has been a reduction in prices and market power in 2024 due to recent entry (MSA, 2024c). This is consistent with the boom and bust cycle of market power in Alberta that has been documented in Brown et al. (2023). A recently approved merger between the first and third largest generators in the province raises concerns over how market concentration will evolve going forward (Competition Bureau Canada, 2024).

permitted to submit bids in the DAM and RTM. This provides scope for purchasing energy in the DAM and selling this energy back in the RTM when real-time conditions are tight and demand reductions are possible. This symmetric treatment of generation and demand in the wholesale energy market is key to avoiding the use of baselines that are often used in current demand response programs to estimate demand reductions, an approach criticized extensively in the literature (Bushnell et al., 2009).[28] To the extent that the demand side participates, it can alleviate market power pressures and decrease peak demand requirements resulting in a reduction in the need for capacity investment (lowering system costs).

An increase in the wholesale energy price caps, or mechanisms that strengthen scarcity pricing, can reduce resource adequacy concerns.[29] However, in the presence of market concentration, this can raise concerns of elevated scope for market power rents. These concerns are also prevalent in centralized market designs with LMPs because certain generators can have considerable sustained local market power when congestion arises (Woerman, 2019). Automatic *ex-ante* market power mitigation procedures are often implemented to limit market power, particularly local market power in the presence of congestion.[30] Higher wholesale price caps can be complemented with market power mitigation to enhance energy price signals during periods of scarcity but limit the consequences of short-term market power. The difficulty is deciding what is the right level of market power mitigation.

The use of market power mitigation is a topic of considerable interest in Alberta. Interim reforms described in Section 5.1 were developed in response to high prices deployed a market power mitigation regime (Government of Alberta, 2024a). The interim market power mitigation limits bids for natural gas generators to the greater of \$125/MWh or 25 times the day-ahead price of natural gas for firms with a market share above 5%. The bid mitigation mechanism is only triggered once the monthly short-run revenues in excess of the operating costs of a hypothetical combined cycle natural gas generator exceed one-sixth of the annualized unavoidable cost. The argument for this approach is that firms can earn short-run market power rents to cover fixed costs, but there is a "safety valve" on the amount of market power rents while being feasible to implement within the existing market tools in a short period of time. In market reforms, it will be important to also consider the scope of local

[28] For a detailed discussion of demand side participation in the electricity sector, see Wolak (2021) and Wolak and Hardman (2021).

[29] Several jurisdictions have implemented an additional market mechanism called the Operating Reserve Demand Curve (ORDC) that serves as an administrative-determined pricing tool to elevate prices during periods of supply scarcity (Hogan, 2013). However, these mechanisms have been criticized for their administrative nature and the ability of its uncertain stream of revenues to motivate large capital investments (Bajo-Buenestado, 2021).

[30] For a detailed discussion of bid mitigation methods and challenges, see Graf et al. (2021a) and Adelowo and Bohland (2024).

market power and its interaction with the broader market design.

Finally, many restructured markets have developed broader mechanisms to promote investment and taken a stronger view on market power mitigation, imposing strong requirements that attempt to limit its extent. Many jurisdictions have moved towards capacity payment mechanisms that provide payments to generators for making their capacity available, supplementing revenues provided for energy and ancillary services. While capacity mechanisms have successfully achieved regulatory-determined capacity levels, they have been the subject of considerable critique. This includes their considerable complexity, regulatory-determined parameters raising concerns that capacity markets lead to overinvestment, high cost, and difficulty assigning capacity value to renewable resources (Garmlich and Goggin, 2019; Wolak, 2022; Holmberg and Tangerås, 2023). Given these critiques, and the previous move to adopt a capacity market in Alberta that was subsequently terminated, a move to a capacity mechanism is not likely to succeed.

An alternative approach is to develop a market mechanism that relies on increased forward contracting. Wolak (2022) outlines a detailed proposal for a standardized fixed-price forward contracting approach. At a high level, load-serving entities would be required to procure a fixed amount of energy in advance using commonly used forward-contracting instruments. These contracts would be signed with generators, providing them with a fixed price for supply well in advance of delivery. There is a large empirical literature that demonstrates that forward contracts reduce generators' incentives to exercise market power (Allaz and Vila, 1993; Wolak, 2007; Bushnell et al., 2008). This contract-based market design could be complemented by an increase in the energy price cap, alleviating the core driver of the concerns over resource adequacy, while simultaneously having reduced concerns over market power rents. Taken together, this approach is argued to facilitate risk-hedging for both generators and consumers, providing scope for enhanced short-run pricing signals in energy markets, and reducing generators' incentives to exercise market power resulting in a reduced reliance on administrative market power mitigation tools. For a detailed summary of this approach in the Alberta context, see Shaffer and Wolak (2024).

6 Conclusions

Like many jurisdictions worldwide, Alberta's electricity market is undergoing a period of transformation with an increasing reliance on renewable generation. However, Alberta's market design is simplistic in its market-clearing. The market lacks a centralized unit commitment mechanism, no market clearing in advance of the real-time market, and a congestion management mechanism that relies on out-of-market re-dispatch. We discuss ongoing challenges that have arisen due to the interaction between renewable capacity growth and existing market design features, including short-run operational challenges arising from a lack of a unit commitment mechanism, increasing transmission congestion and the divergence between locational energy value and prices, and concerns over elevated market power in recent years and the continued reliance on strategic behavior to promote resource adequacy.

Rising operational concerns have led the Government of Alberta to direct the system operator to reform the market design, providing high-level policy direction on key market elements. We describe approaches employed in other jurisdictions to more cost-effectively integrate renewable generation while maintaining reliability. In particular, we summarize the principles of centralized/integrated market designs employed in restructured markets in the US. These markets include multi-settlement day-ahead and real-time markets that account for the physical realities of the transmission system and unit constraints. This provides improved coordination of resources in advance, facilitates unit commitment, and provides scope for enhanced energy market price signals with more spatial granularity. There is a growing empirical literature that demonstrates the value of these market reforms.

We describe how the Government of Alberta's direction letter for proposed market reforms does (and does not) fit within these centralized market designs. In particular, the Alberta government is proposing to adopt a day-ahead market. However, not all day-ahead market designs are created equal. It will be key that Alberta learns from lessons in other jurisdictions and adopts key market design features that account for the physical realities of the system during day-ahead market-clearing. One potential barrier outlined in the direction letter to achieving this objective is the requirement for a single province-wide price. The lack of nodal pricing will lead to the requirement to leverage re-dispatch mechanisms to manage transmission congestion, an approach that has been increasingly criticized as renewable output increases (Graf et al., 2021b; Eicke and Schittekatte, 2022).

As renewable generation capacity expands, it will be important for jurisdictions such as Alberta to ensure they are adopting a holistic package of reforms that develops a market model that best reflects the physical realities of the power system. There is a growing body of empirical evidence pointing to key market design reforms that can be employed to facilitate renewable integration while ensuring the electricity system remains reliable and cost-effective. While such reforms are challenging and can reflect a considerable deviation from current market operations, it is important that jurisdictions do not remain anchored in historical market design elements at the cost of overall efficiency.

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