A report *from*

ALBERTA FEDERATION OF LABOUR

Power in the Public Interest

Re-regulation and increased public ownership in **Alberta's electricity sector**

October 2024

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The Alberta Federation of Labour (AFL) is the leading voice for working Albertans, representing 26 affiliated trade unions and over 170,000 unionized workers across Alberta.

LETTER FROM THE PRESIDENT

It’s time for a solution

I am pleased to present this important report on Alberta’s electricity sector.

For too long, we’ve watched as deregulation and creeping privatization have failed our workers and communities. We’ve seen prices soar, reliability plummet, and good union jobs disappear. It’s not just about lowering bills. It’s about creating good jobs, ensuring a stable grid, and accelerating our transition to clean energy.

This report, prepared by Edgardo Sepulveda, a regulatory economist with thirty years of experience, reveals the shortcomings of the current system with one data point after another and offers a concrete vision for change. We can create a system that works for all Albertans, not just corporations, by bringing back regulation and increasing public ownership.

Workers also have to pay high electricity prices, and their prosperity is at risk if Alberta cannot maintain and attract companies that rely on reliable, inexpensive and clean electricity to power their operations.

Workers know this sector better than anyone. They are the ones that converted coal generation plants, built new transmission infrastructure, and fixed the distribution system after storm damage. Labour must have a seat at the policy-making table when discussing the future of this critical industry.

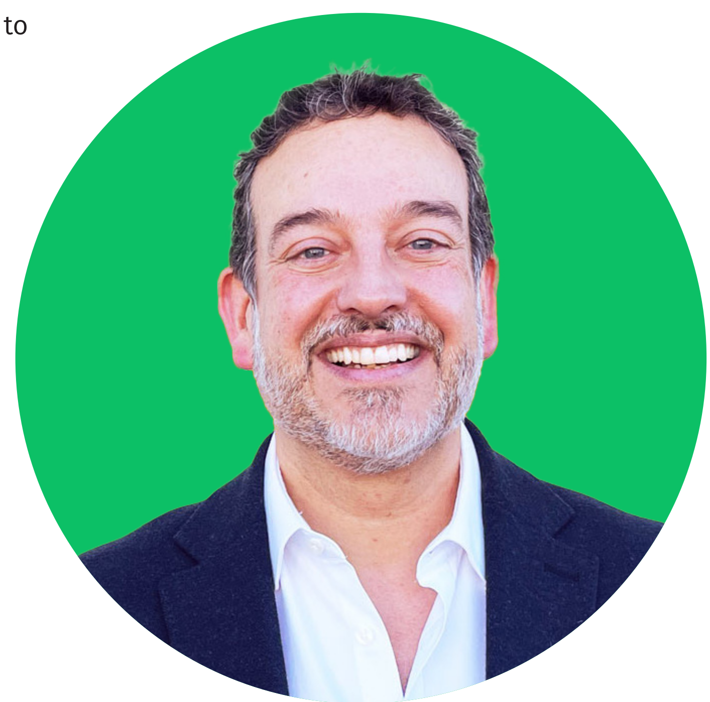
The Alberta grid is small and concentrated, so it’s no surprise that corporations, which are allowed too much market power, are gaming the system. We demand a return to the regulation of corporate profits in the generation segment to protect consumers from further price-gouging.

We demand the creation of **Alberta Power**, a new Crown corporation that, together with bigger municipal utilities, would put control of our electricity back in the hands of the people.

As workers we have the right to demand better. Read this report, share it widely, and join us in the fight for an electricity system that serves the public interest.

In solidarity,

Gil McGowan
President
Alberta Federation of Labour



List of Abbreviations

AESO	Alberta Electricity System Operator
ASA	*Alberta Sovereignty Within a United Canada Act*
AUC	Alberta Utilities Commission
CCF	Co-operative Commonwealth Federation
COS	Cost of Service
CPI	Consumer Price Index
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
EEA	Energy Emergency Alert
EEA3	Energy Emergency Alert, Level 3
EELC	Edmonton Electric Lighting Company
EEMA	*Electric Energy Marketing Act*
EUA	*Electricity Utilities Act*
GDP	Gross Domestic Product
IESO	Independent Electricity System Operator
IPP	Independent Power Producer
ISO	Independent System Operator
kWh	Kilowatt-hour
LTC	Long-Term Contract
MSA	Market Surveillance Administrator
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPG	Ontario Power Generation
PBR	Performance-based Regulation
PPA	Power Purchase Arrangement
REA	Rural Electrification Association
REM	Restructured Energy Market
REP	Renewable Electricity Program
ROE	Return on Equity
RRO	Regulated Rate Option
TWh	Terawatt-hour
UFA	United Farmers of Alberta
WACC	Weighted Average Cost of Capital

Contents

Executive Summary

For multiple days in January 2024, record-breaking winter temperatures reaching -40°C or even -50°C across much of Alberta prompted Environment Canada to issue unnerving extreme cold warnings.

Any exposed skin could suffer frostbite in under a minute, said experts. Yet at this moment of most urgent need, the province's electricity grid was barely up to the task, with reserve power down to as little as 10 megawatts at one point on a Saturday evening. As a result, the Alberta Emergency Management Agency was forced to issue an emergency alert urging residents to turn off unnecessary lights and appliances, to avoid cooking, to not plug in block heaters, and to delay charging any electric vehicles, as presented in ***Figure E1***.

If Alberta households did not conserve electricity fast enough, warned the Alberta Electricity System Operator (AESO), then rolling blackouts—in this bleakest of bleak midwinters—would be necessary. The province got lucky this time, however. Everyone pulled together and quickly slashed their electricity usage. Thankfully no one died.

Let us hope we are as lucky next time, for a next time is sure to come with a grid as fragile as Alberta's, even though our electricity is the most expensive in Canada.

The near-deadly catastrophe in 2024 was no one-off. While Alberta accounts for less than 2% of North America's electricity demand, in the last two years the province's grid has suffered the indignity of being responsible for more than a third of the entire continent's most severe level of Energy Emergency Alerts — when blackouts are imminent or in progress, as measured by the North American Electric Reliability Corporation (NERC).

Figure E1*: Alberta Emergency Alert issued January 13, 2024.*

Critical: Civil Emergency - Alberta
Issued Jan 13, 2024 at 06:44 PM

Source: Alberta Emergency Management Agency
Issued: Jan 13, 2024 at 06:44 PM
History:
Alert: Jan 13, 2024 at 06:44 PM

Description: This is an Alberta Emergency Alert issued by the Alberta Emergency Management Agency.

Extreme cold resulting in high power demand has placed the Alberta grid at a high risk of rotating power outages this evening.

Area: This alert is in effect for Alberta.

Affected areas (1):

- Alberta

Action to take:

- Albertans are asked to immediately limit their electricity use to essential needs only
- Turn off unnecessary lights and electrical appliances
- Minimize the use of space heaters
- Delay use of major power appliances
- Delay charging electrical vehicles and plugging in block heaters
- Cook with microwave instead of stove

Source: Alberta Emergency Management Agency (2024).

And yet the province is also consistently home to the highest electricity prices in the country. As we show in this report, during the deregulation period Alberta's electricity consumer price index increased by an average of 1.8% per year higher than that of Canada as a whole, or double the difference prior to deregulation.

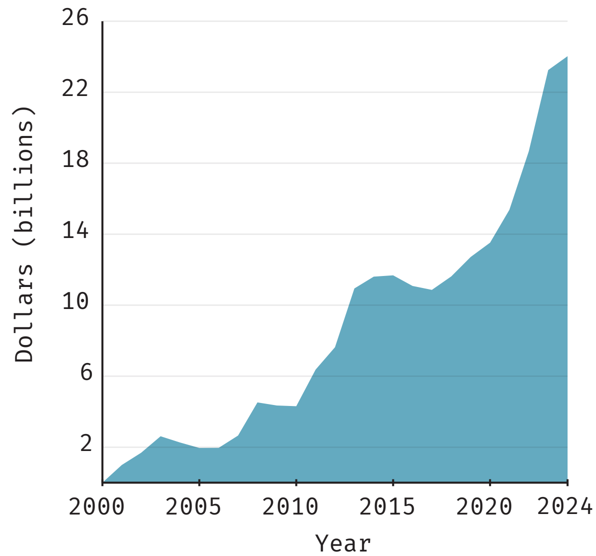
This means that since 2001, Albertans have paid about **$24 billion more for their electricity** than if they had paid the same prices as other Canadians.

These excessive overpayments are presented in ***Figure E2***. Residential consumers accounted for about $7 billion of that $24 billion total. These high electricity prices are an injustice to all Albertan families but especially to the least advantaged, who spend a far greater proportion of their income on energy than others. In this report we also show how, since the early 2000s, volatility of prices has increased as well, making it harder for these families to plan their budget. Beyond the obvious unfairness of such price increases and volatility, these phenomena are also a strain on economic development, with **industrial, commercial and farm users overpaying $17 billion since 2001**. This drain on the economy holds everyone back, regardless of income or status. Families lose both ways, they have to pay high electricity prices, and their prosperity is at risk if Alberta cannot maintain and attract companies that rely on reliable, inexpensive and clean electricity to power their operations.

So, what happened?

How did Alberta end up with such a fragile grid rife with price-gouging and volatility, while other provinces are doing so much better?

***Figure E2**: Cumulative difference between Alberta System Costs, with Alberta prices versus Rest of Canada prices, 2001-2024.*



Source: Hydro-Quebec (2023 and previous), Bishop et al (2020), AUC (2024a), Statistics Canada (2024j), Author's calculations.

This report unravels that mystery. It is a tale of a market-fundamentalist experiment in deregulation imposed on the grid that, prior to 2001, had a healthy balance of private and public enterprises and protected the public from the exercise of corporate market power. The promoters of the experiment believed that the electricity sector should be "disrupted." It would no longer be necessary to control profits through regulation because competition in the newly-created generation market would protect consumers in Alberta's small and concentrated market, where the largest five generation entities already control 54% of the market.

Two decades later, it has become clear that the promises of the deregulation experiment were based on no more than an ideological leap of faith. The evidence is in, and deregulation has turned out to be very costly indeed. In addition to higher and more volatile prices and Alberta's grid becoming the most fragile in North America, privatization has increased, electricity sector employment has stagnated, union rates have plummeted, and corporate profits have skyrocketed as a result of the exercise of market power.

The government's proposed "Restructured Energy Market" (REM) reforms are no solution. The process was rushed, no evidence was provided for some of its assessments and the proposals constitute very modest tweaks that other competitive jurisdictions have already adopted. The fact remains that after the dust is settled, Alberta will remain as only one of two jurisdictions in North America (the other being Texas) that maintains an energy-only market. Alberta is even more of an outlier in Canada, being the only deregulated market, with other provinces having regulated or hybrid markets. Alberta is also an outlier when it comes to ownership of the generation segments, with only 9% public ownership, way below our neighbours in British Columbia, Saskatchewan, and Manitoba that average more than 80% via their provincially-owned Crown corporations.

We show how by controlling profits through regulation and establishing **a new, provincially-owned Crown corporation**, Alberta can bring prices back under control, dampen volatility and plan better for a new era of electrification as we decarbonize our economy.

The process of re-regulation would be straightforward, for the province is home to an abundance of institutional experience to back it up. Unlike the deregulation experiment, re-regulation would not be a leap of faith that would require the creation of new institutions, costly auctions, and market uncertainty. The well-respected Alberta Utilities Commission (AUC), whose predecessor

***Figure E3**: Edmonton Power appliances promotional vehicle*

Source: Edmonton Power Historical Foundation (2002).

agencies date back to 1915, continues to regulate the distribution and transmission segments (those parts of the grid separate from generation, basically the power plants). Before deregulation, the AUC also regulated the generation segment of the grid.

Re-regulation could take different forms and could include a combination of traditional Cost of Service (COS) and performance-based regulation (PBR) as is currently applied by the AUC to the transmission and distribution segments, as well as long-term contracts (LTC). These would be tailored to best achieve the objectives of ensuring lower, more stable prices and increased reliability while maintaining incentives to invest to meet electrification goals.

Increased public ownership in Alberta would be implemented in the same manner as in other provinces: a long-term process that combines organic growth and the acquisition of privately-owned companies based on the principle of promoting democracy. In distribution, Alberta already has vibrant municipally-owned utilities and Rural Electrification Associations that serve 60% of Albertans. These include Canada's first municipal publicly-owned electric utility, established in 1902 in Edmonton (see ***Figure E3***).

A first next step in this process is the creation of provincially-owned Crown corporation, Alberta Power, which could own and operate distribution, transmission and generation assets and, as with other generation entities, would be subject to regulation by the AUC. Alberta has a long history with Crown corporations, including with the unique-in-Canada ATB Financial. To encourage increased local ownership, communities that so desired it would be encouraged to build or expand their own municipal utilities, or to have Alberta Power do so on their behalf. The financing for increased municipal ownership would come from existing or revamped provincial financial assistance programs, such as the Loans to Local Authorities program or financing through the *Rural Electrification Loan Act.*

It turns out that electricity is not a regular commodity; it has unique characteristics and a strategic role in the economy. The grid is instead one of the most complex and most essential machines humanity has ever devised. We have more than a century of experience that shows that our proposed regulated model with increased public ownership including a Crown corporation not only works in practice but is ideally suited to expanding the generation necessary to decarbonize our economy.

It is time to end the catastrophic, dangerous deregulation experiment and to promote a healthier public-private balance in Alberta.

Chapter 1: An Economic History of Electricity in Alberta →

Chapter 1

An Economic History of Electricity in Alberta

From the very beginning of the electrification of Alberta in the late 19th century, there had been a healthy mix of both private and public enterprises providing liberating, new energy technology to its residents and industries under various economic arrangements.

A Popular Fury at Monopoly Abuses

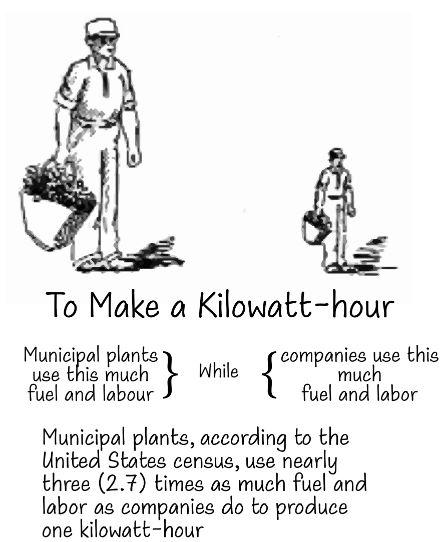
The reason for the substantial role of the public sector in electricity flows from both the nature of electricity as a commodity and the geography of the province — something common to most other Canadian provinces. This explains why public electric companies have played such a key role in the country's development. As we will see, while Alberta is a very different place today than it was a century ago, the fundamentals relating to electricity have not changed. And so, when we take this longer, wider view, the deregulation of the generation segment of the electric grid beginning in 2001, and its creeping privatization, constitute short-term outliers that should be corrected.

As in much of the rest of the world, electricity was first available to Alberta's urban populations. In the 1880s and 1890s, Edmonton, Calgary, and Lethbridge all entered into multi-year franchise agreements with private entities to provide electricity: the Edmonton Electric Light Company, Calgary Power and the Lethbridge Electric Light Company. The "franchises" set out the terms and conditions under which the private utility provided service. These terms included the geographic boundary (the franchise territory), payment obligations to the municipalities, and exclusivity provisions (requiring that no new franchises be issued over the course of the agreement). These cities had no choice but to depend on the private sector initially. At the time, most municipal governments either did not have their own financial resources or, if they did, sufficient means to borrow in order to purchase the machinery and the rest of the infrastructure required to provide what was then considered by many to be a novelty rather than a necessity. That changed in the 1900s after most contracts expired.

At the turn of the century, the Canadian and American progressive movements had launched exceedingly popular political fights against corporate and monopoly abuses. Rapid industrialization across the continent and new governmental structures combined to produce widespread corruption and vast corporate concentration in monopolies in multiple sectors. In the electricity sector, the egregious price-gouging and lack of coverage in less profitable areas, led many politicians across the political spectrum to call for public ownership of electricity. Alberta was not immune to this voter revolt.

As soon as the 10-year franchise agreement granted by the City of Edmonton to the Edmonton Electric Lighting Company (EELC) expired, the City borrowed the funds to buy out EELC for $13,500. Edmontonians can be proud that in 1902, Edmonton Power became Canada's first municipal publicly-owned electric utility. ***Figure 1*** shows that opponents of public power continued to try to persuade Edmontonians well into the 1920s to privatize Edmonton Power. In spite of this, almost identical processes of cities taking over private electric companies soon spread throughout Canada and the US, where it was called "municipalization".

***Figure 1**: "Opposition to Public Operation" pamphlet distributed in Edmonton, 1920s*



Source: Edmonton Power Historical Foundation (2002). (Author recreation)

Before we dive any deeper into the history and political economy of electricity in Alberta, we will explain in rough terms the main components of any electric grid, as there are different politics and economics attached to each component.

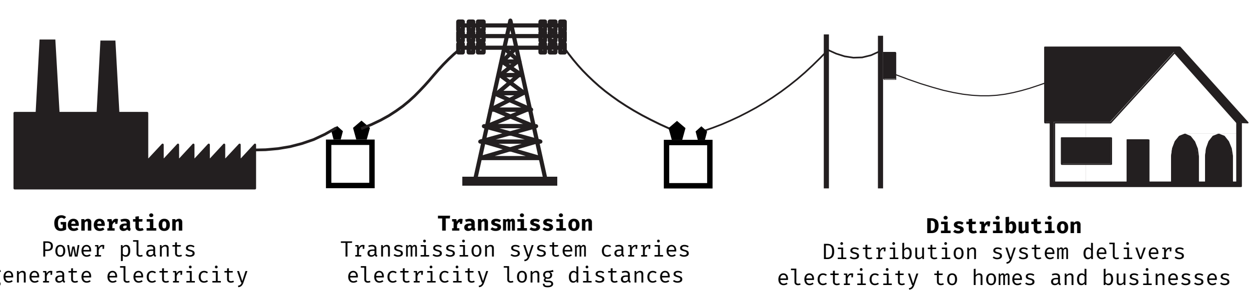
Figure 2 is a simplified schematic of the three main components of the electricity system that was first developed in the 1890s: generation, transmission, and distribution. Furthest upstream are the generation plants, also called power plants or generating stations, that produce the electricity. In the early days, generation was constructed close to where the electricity would be consumed. Later on, it began to be built farther away to accommodate urban growth. High-voltage transmission then carries electricity from these distant plants to the source of demand, or "load" — the cities and other consumers. Once in the city, the electricity is then carried to the consumer by the lower voltage distribution systems. A firm that owns and operates all three segments is referred to as a "vertically-integrated" utility. Otherwise, the utility is described as "unbundled" or "standalone."

In 1902, Edmonton bought the beginnings of a distribution system from the EELC, and some in-city generation assets. Details are scarce, but it is likely that they purchased some very limited in-city transmission. The city terminated EELC's franchise agreement to provide service anywhere in the city, including areas that were not initially served. That responsibility then fell to what would become Edmonton Power, a municipally-owned, vertically-integrated utility that would go on to become one of the three major vertically-integrated utilities in Alberta (later called the "Big Three").

A century later, in the lead-up to deregulation, Edmonton Power was transformed from a municipal department into a separate corporate legal entity with a shareholding structure and board of directors. Though still technically public, it had been corporatized, making it ready for the chopping block. The new entity was named EPCOR, with the City of Edmonton as its sole shareholder. In 2009, EPCOR disintegrated its generation business and began the process of privatizing its generation assets, now held by a separate firm, Capital Power. EPCOR no longer holds any common shares in Capital Power, meaning it has been fully privatized.

***Figure 2**: Main Components of a Traditional Electricity System*

Source: Author's design.



Calgary, Lethbridge, and Other Municipally-Owned Utilities

Calgary meanwhile contracted with its private utility provider, Calgary Power, for a longer period. Incorporated in 1909, Calgary Power went on to expand its footprint beyond its namesake city to become the largest utility provider in Alberta. In the same manner that the private EELC had been required to operate under a franchise agreement from Edmonton to operate in that city, Calgary Power also operated under a franchise agreement. However, this time granted by the province to provide distribution service in its franchise "territory," which included not just Calgary, but the south and east of the province.

In 1928, the municipality of Calgary decided to purchase the in-city assets of Calgary Power and consolidate them into what would become the City of Calgary Electricity System. Then in 1996, similar to Edmonton's EPCOR process, this Calgary Electricity System was corporatized into a new legal entity, ENMAX.

Calgary Power continued to operate outside of the municipality of Calgary, providing distribution in its franchise territory (excluding the franchise areas of the municipal utilities) and transmission and generation services, including to Calgary and most of the other municipal utilities. In 1981, Calgary Power changed its name to TransAlta to reflect its national and international expansion. Soon after deregulation, TransAlta sold off its transmission assets to another firm, AltaLink (which to this day remains the largest transmission provider in Alberta), and its distribution systems to yet another private entity, Utilicorp, which in turn sold them to the FortisAlberta, the natural gas firm, which now contracts about 30% of all distribution customers.

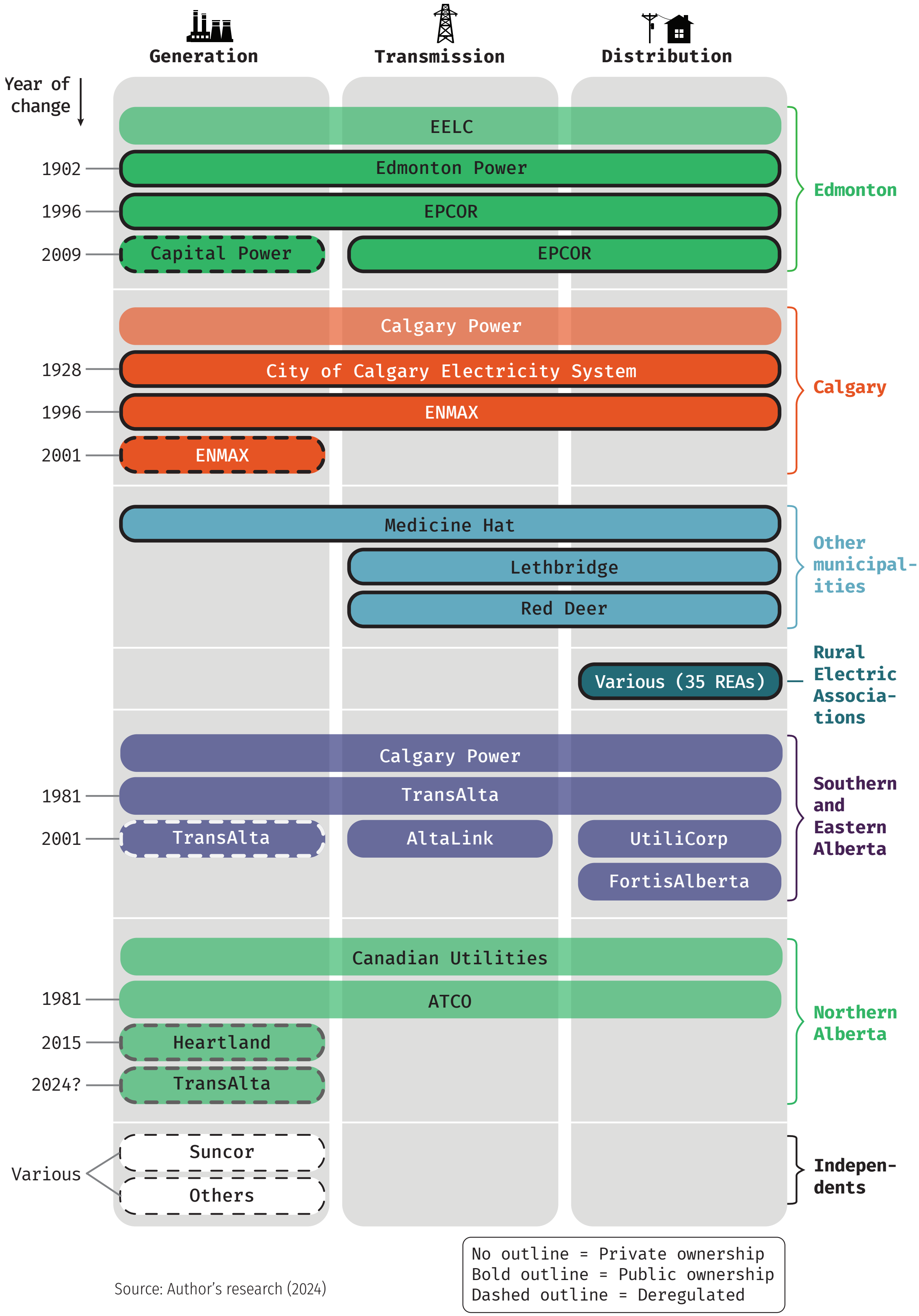
In Lethbridge in 1907, the municipality purchased the facilities of the privately-owned Lethbridge Electric Light Company. Around this time, Medicine Hat, Red Deer, Cardston, Ponoka, Fort Macleod, and Crowsnest Pass also bought out their respective private companies to establish municipally-owned utilities. These latter utilities continue to exist as public sector entities.

As we will explore further in Chapter 4, today, these remaining public utilities have a market share of 58% of customers in Alberta. For more than a century, they have served their residents and have been the public bulwark that has balanced the rest of the private system, represented for most of this period by Calgary Power in the south and east of the province and a private firm called Canadian Utilities (later acquired by ATCO) in northern Alberta.

Canadian Utilities has a slightly different origin story. This electric company also delivered natural gas. It was founded in 1911 and later consolidated with a number of other energy companies, notably Northland Power in 1961. Canadian Utilities' franchise territory covered much of the north of the province, other than the areas where the municipal utilities operated. Canadian Utilities was acquired by ATCO in 1981. Prior to deregulation, ATCO was the second largest of the "Big Three." It now has about 12% of all distribution customers. ATCO managed to retain its transmission business and, together with AltaLink, enjoys a roughly 90% market share, with the rest provided by the municipal utilities for in-territory transmission.

This mosaic of different names and structures for different regions, the mixture of public and private ownership, and who is responsible for supervision of the three different segments of the grid can sometimes be confusing. To help, we have put together ***Figure 3***, which provides a graphical summary of the evolution of the Alberta electricity system since the 1900s, as described in

FIGURE 3: *EVOLUTION OF ALBERTA'S ELECTRICITY SECTOR*



Source: Author's research (2024)

this chapter and in the rest of our report, broken down by generation, transmission, and distribution segments, and whether the entity is public or privately-owned.

We have seen that the history of electricity in Alberta began as private, as municipalities did not have the ability or the resources to electrify their regions by themselves, but very quickly in reaction to monopoly abuses, municipalization became widespread as happened throughout much of North America, albeit still with a considerable role of the private sector. Then in the 1980s and 1990s in Alberta, corporatization of these municipal structures preceded unbundling, deregulation and partial privatization in the 2000s.

What happened that brought about this change? And why is it so common in the rest of Canada to still find large parts of the grid, or even all of it, under public ownership? To answer these questions, we have to turn the clock back once more, this time to just after World War II.

The 1948 Public Ownership Plebiscite

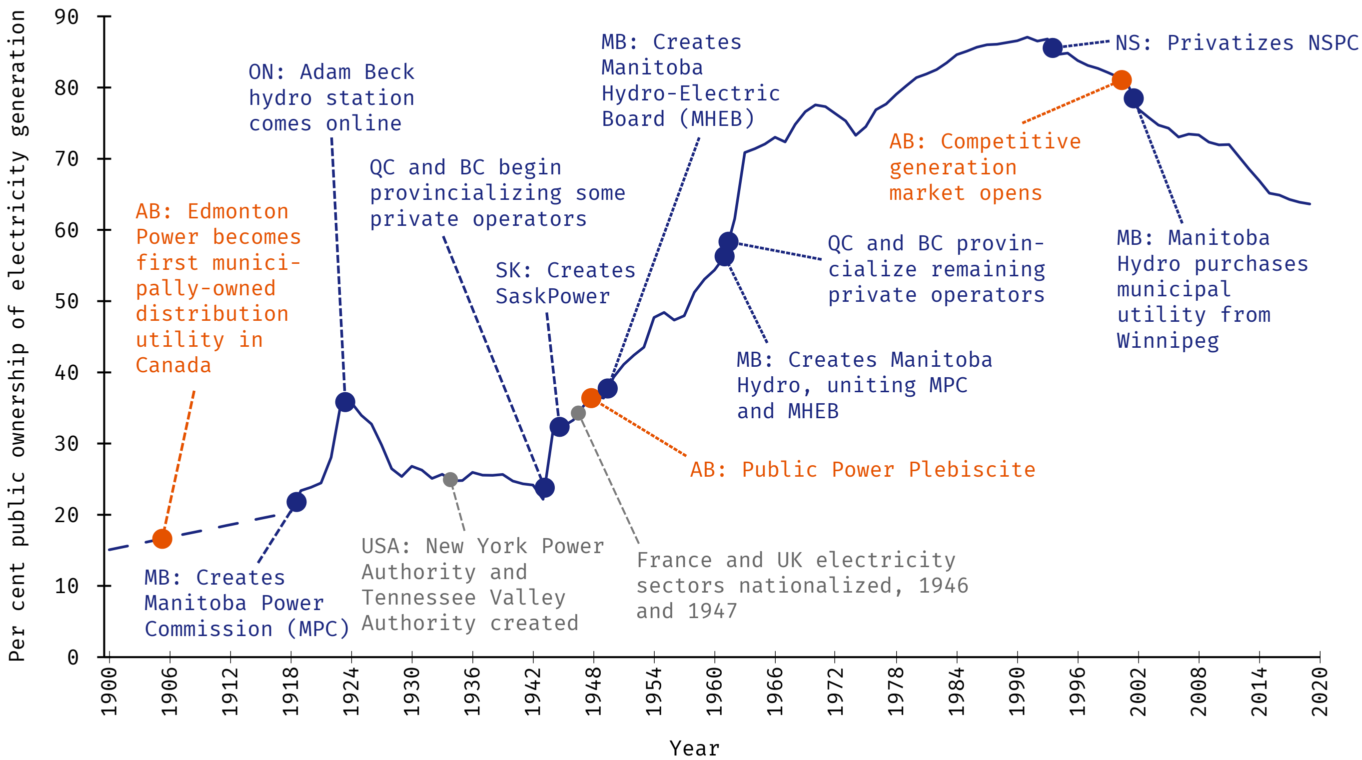
Given the heated nature of political discussions related to the electricity sector, Albertans will not be surprised that politics and electricity have long coincided in our province. The history of all this is rich, but we have not gone into the minutia of the local advocacy surrounding municipalization. Instead, we explore three key instances in which electricity was an important provincial policy matter and political hot potato.

Public ownership has been the subject of broad political discussion twice in Alberta (we hope to make it a third time). One such period was the early 1900s, around the time of municipalization in Alberta and elsewhere, as we have already seen. The second period was during and immediately after World War II. At this time, British Columbia and Quebec began to construct what would eventually become the Crown corporations BC Hydro and Hydro-Québec. In 1944, the Co-operative Commonwealth Federation (CCF, the forerunner to the New Democratic Party) government in Saskatchewan created SaskPower. And this was an international movement; the electricity sectors in the UK and France were nationalized in 1946 and 1947 respectively, in the former case by a centre-left government and in the latter case by a centre-right one. Regulation and public ownership of electricity was not a partisan issue. The same arguments behind municipalization—that the profit motive of a private electric company was not always aligned with the values, needs, and goals of a city or town—were now being made at the provincial or national levels. Electrification was now seen as vital infrastructure essential to nation-building. Governments did not want to have to wait until market actors found buildout of such infrastructure profitable enough. Put another way, capitalism was too slow to make capitalism work.

In ***Figure 4***, we show that the proportion of the grid in public ownership in Canada continued to increase until the early 1990s. By then, the new political economy of neoliberalism—a belief that markets arrive at better decisions than voters, and by extension, their governments in almost all cases—and its preference for private ownership would start to reduce public ownership. This trend has continued to this day.

Right across the prairies, the push for public ownership had largely been driven by the need to speed up rural (farm) electrification. Building out the infrastructure of the electric grid to serve the needs of sparsely populated farmland was just not profitable compared to building it in densely populated cities. Most of Alberta's population

Figure 4: *Per cent of Electricity Generation that is Publicly Owned, Canada*



Source: (Statistics Canada 2021 and previous), Author's research and calculations. 1900-1916 are Author estimates; 1917-2019 are actuals.

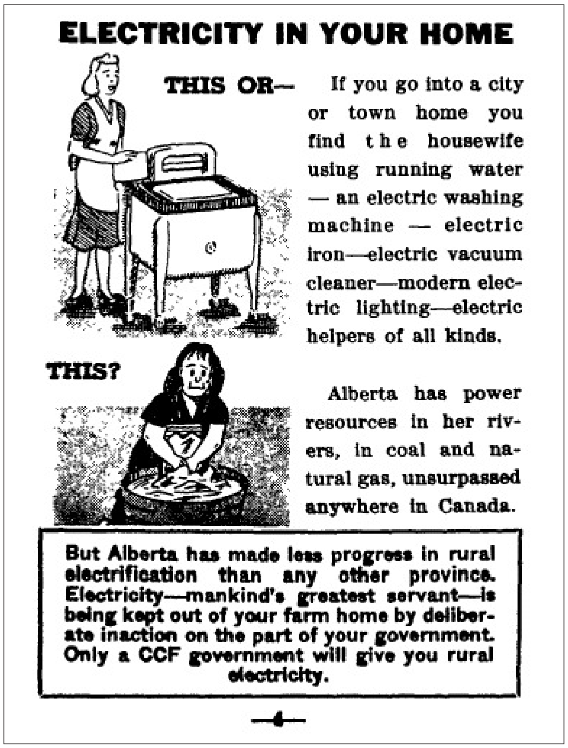
did not live in the cities at the time, and farm electrification lagged behind the other provinces. The Government of Alberta created the Alberta Power Commission in 1944 to study the issue. There was a popular perception that outside of the cities, which had their own municipal utilities, private utilities such as Calgary Power, Canadian Utilities, and Northland were not interested in extending services except to the most profitable farms. There was a growing desire to create a provincial utility that could simply be directed by the government to speed up rural electrification, regardless of profitability.

Heading into the 1948 provincial election, the Alberta CCF advocated for just such public ownership. The United Farmers of Alberta (UFA), which had formed government in Alberta from 1921-1935, and the newly formed Alberta Farmers Union both supported public ownership. Public ownership was also an issue of women's liberation. ***Figure 5*** comes from a CCF Campaign pamphlet focusing on how electricity on the farm could free women and girls from the drudgery of many domestic chores.

Under this widespread pressure, the Social Credit government of Premier Ernest Manning decided to put the question to a plebiscite held with the 1948 general election. ***Figure 6*** shows the plebiscite and the CCF's support for the second option, the creation of a publicly-owned utility, in effect what today we call a Crown corporation.

Despite widespread support for the concept, it was insufficient, and the partisans of public utility lost. Nevertheless, the result was extremely close. ***Table 1*** shows just how close, with the "status quo" first option edging out the public-ownership option by 50.03% to 49.97%, a difference of only

Figure 5: *Image from 1948 Alberta CCF Campaign Pamphlet*



Source: CCF (1948a)

Figure 6: *Image from Alberta CCF Campaign on 1948 Plebiscite*

The C.C.F. Urges the Electors to Vote 1 For the Second Question

ELECTRIFICATION PLEBISCITE

Do you favor the generation and distribution of electricity being continued by the power companies as at present?

OR

Do you favor the generation and distribution of electricity being made a publicly-owned utility administered by the Alberta Government Power Commission?

Mark Figure 1 Opposite Your Choice

Source: CCF (1948b) (Author recreation)

Table 1: *Results of the 1948 Plebiscite, Alberta*

PLEBISICITE RESULTS COMPARED
WITH POPULATION CHARACTERISTICS (1946):
URBAN AND RURAL RIDINGS, NORTHERN AND SOUTHERN RIDINGS

	Private ownership vote	%	Urban+ pop. %	Public ownership vote	%	Farm pop. %
City* ridings	58,099	61 4	100.0	36,461	38 6	-
Non-city ridings	81,892	44.2	24 99	103,379	55 8	75.0
Northern** non-city ridings	30,637	37.9	12.9	50,198	62.1	66.3
Southern non-city ridings	51,255	49.1	25.8	53,181	50.9	54.4
Total	139,991	50.03	44.1	139,840	49.97	41.8

Source: Schulze (1989)

151 votes. Recognizing this, the incoming Social Credit government did apply “moral suasion” on the private operators to do more, and still moved in the direction of a public option, but through a different path than a provincially-owned vertically-integrated utility. The government established a rural financing facility modelled on the successful Rural Electrification Administration in the USA to facilitate the creation of rural cooperatives, the Rural Electrification Associations (REA).

Farmers formed these local REAs, and other members joined voluntarily and contributed the startup cash. Farmers borrowed from the province for further financing and sought out the technical expertise they needed. Alberta was the only province in Canada where rural residents successfully used REAs as a means of rural electrification. To this day, there are about 35 REAs serving about 35,000 members, or about 2% of all distribution customers in Alberta.

But because there was never a single vertically-integrated public utility, it would become much easier for the ideologues of neoliberalism to deregulate, unbundle (disintegrate), and privatize the public elements of Alberta’s grid. Even in Ontario, which saw the publicly-owned Ontario Hydro broken up in the late 1990s, to this day large chunks of that province’s grid remain in public hands even after deregulation.

But Alberta’s smaller, municipalized utilities were too weak and so proved much easier ideological pickings. And, as we shall see, the deregulation process weakened them even further.

The 2001 Deregulation Process

From a practical perspective, there were two prior steps in the long process needed to facilitate deregulation. In 1974, Alberta’s transmission system started to be operated on an integrated basis, with each of the utilities sharing the role of system controller. Under pressure from residents and industry based in northern Alberta served by (what would become) ATCO in 1982, the Government of Alberta decided to “geographically average” transmission and generation prices across the province.

The *Electric Energy Marketing Act* (EEMA) was sold by the Government of Alberta as a “fairness” initiative. The traditional franchise model has always had price differences to reflect underlying costs. But this did seem unfair. Why should one citizen of Alberta pay a higher price than another just because they lived in a different location? So, the EEMA delinked prices and costs, by mandating transmission and generation services to be sold at regulated rates approved by the AUC to the EEMA agency, and then for the agency to then sell them back to the producers at a uniform rate. This arrangement would facilitate deregulation by introducing the concept of a generation “pool” of electricity.

Market shares during this period were relatively steady. On the distribution segment, municipal utilities and REAs had about 60%, with TransAlta and ATCO holding the remaining 40%. On generation, the “Big Three” of Edmonton Power, TransAlta, and ATCO owned about 90% of the generation assets (about 45%, 22%, and 22%, respectively).

By the early 1990s, the government decided to disintegrate the sector to deregulate the generation segment, along the lines of the model that was implemented by the UK government under Prime Minister Margaret Thatcher. Deregulation entailed no longer controlling profits or prices, based on the theory that competition in the newly created generation market would be sufficient to protect consumer interest, and result in cheaper prices and increased reliability.

Figure 7, from the Ministry of Energy (1994) report "Enhancing the Alberta Advantage," lays out the government's motivation and objectives with respect to prices and reliability, further arguing that the "proposed restructuring would help hold down electricity rates." They believed that electricity was a commodity like any other, and increased competition would decrease prices over time.

***FIGURE 7**: EXCERPT OF ALBERTA MINISTRY OF ENERGY 1994 POLICY*

> The challenge now facing Alberta is to preserve the very real strengths of our existing electric industry, while drawing on forces of competition to build an improved system for the future. On the one hand, Alberta currently benefits from a reliable system and electric rates that are among the lowest in North America. On the other hand, changes in industry structure and regulation are needed to take advantage of competition for the benefit of all consumers.

Source: Ministry of Energy (1994)

In 1995, the legislature passed the *Electricity Utilities Act* (EUA) which took effect in 1996 and mandated a series of steps to be taken in preparation for full deregulation in 2001. This included the creation of the balancing pool, the formulation and auctioning of the Power Purchase Arrangements (PPAs), the selection of the "Energy-only" type of deregulation to be adopted in Alberta, and the creation of a competitive retail market, where third-party resellers would be allowed to market electricity to end-users on a "contract" basis. Thus these resellers were in competition with the incumbent distribution utilities.

The deregulated generation market and the competitive retail market kicked off in 2001. The latter involved a series of transitional measures, including, as in other jurisdictions that have introduced competitive retail markets, a "default" non-contract option that would apply to consumers that did not enter into a contract, either because they decided against it or were ineligible to due to income or credit conditions. This is similar to how low-income households opt for pay-as-you-go mobile phone services as they cannot afford monthly bills, even though on a per unit of service basis, these are often much more expensive.
In Alberta this was called the "Regulated Rate Option" (RRO) and the government required that the incumbent distribution companies provide it in their respective distribution territories.

After the EUA came into effect, the Ministry of Energy (1996) report, "*Moving to Competition*," provided a guide to the new industry structure, promising, as set out in ***Figure 8***, that cost would be lower than otherwise.

***FIGURE 8:** EXCERPT OF ALBERTA MINISTRY OF ENERGY 1996 POLICY*

> In the long term, increased competition and incentive regulation are expected to result in lower costs than the old structure would have provided. This will maintain Alberta's competitive electricity rates, which are among the lowest in North America. In turn, lower rates help the province's industries to remain competitive in international markets — and maintain economic growth and opportunities.

Source: Ministry of Energy (1996)

The EUA contained a number of provisions that weakened the municipal utilities. One was that participation in the newly-restructured market was compulsory. Implicitly directed at EPCOR, it forbade its generation segment to sell to its distribution segment. Instead, it was required to sell into the pool. A loss to localism in favour of centralization. The one exception was Medicine Hat, which lobbied to maintain its vertically-integrated municipally-owned utility. To this day, Medicine Hat remains outside the Alberta Interconnected Electric System operated by AESO.

Another provision was more explicitly opposed to public ownership: limiting the ability of municipally-owned utilities from building additional generation assets. ***Figure 9*** provides the government's rationale; a form of handicapping public enterprises for some of the very advantages that allow them to provide lower-cost services.

Figure 9: *Excerpt of Government of Alberta 2002 Market Reform Explainer*

> Much of the success of Alberta's new industry structure depends on creating a competitive environment in which many suppliers are encouraged to pursue generating projects. This requires a level playing field, in which potential competitors see that they have a fair chance at being able to negotiate contracts to supply power.
>
> In framing the new industry structure, the government recognized that municipally owned generation companies may have certain advantages, including exemption from income tax. Therefore, the Electric Utilities Act stipulates that municipalities can build new generation only under certain conditions. The primary condition in that an independent assessment demonstrates that the project is not benefiting from any tax advantage, subsidy or financing advantage as a result of its association with the municipality.

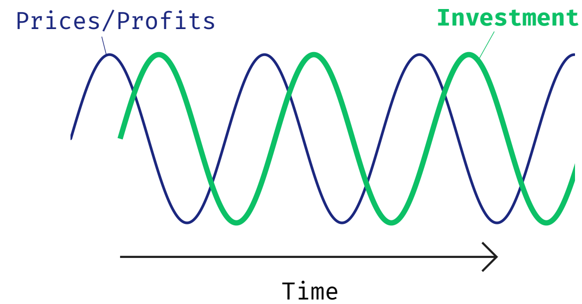
Source: Ministry of Energy (2002)

Developments Since 2015

After relative policy stability for a decade and a half, the election of a new government in 2015 brought on two large policy changes.

"Energy-only" markets, including Alberta's, are designed on a specific model of how firms behave in a competitive market. During relatively slack demand/supply periods, pool prices tend to be lower, towards the marginal cost of the market-

Figure 10: *Idealized Investment & Price/Profit Cycles in Energy-Only Markets*



Source: AESO (2024b), Author's Calculations

clearing technology. This results in sub-normal profits (or losses) because firms cannot make an appropriate contribution to their fixed costs. In the long-term, such a financial situation is not sustainable or desirable. With lower prices, there will be less investment and new entry. Therefore, there will be more and longer instances of tight demand/supply periods, which will result in periods of higher prices. In a competitive market such prices result in super-normal profits, just enough to allow firms to over-contribute to fixed costs to make up for the previous under-contribution. These higher prices are a signal that incents additional investment and new entry. And so forth, prices, profits and investment up and down, over the generation "business cycle," as shown in ***Figure 10.***

Why would a government adopt such a market? One theoretical benefit is that retail prices should be the same or lower than the regulated alternative, while profits should be close to "normal" (returning a competitive market equilibrium return on capital). We discuss in Chapters 2 and 3 whether the empirical evidence supports this idealized vision of energy-only markets in Alberta.

In 2016, the new government proposed to replace the energy-only market with a Capacity market, citing the objective of reducing price volatility in an era of much more variable generation from wind and solar generation, among other reasons. Capacity markets are designed to require more planning in order to achieve greater reliability. The theory of capacity markets is that firms are paid through a mix of capacity payments for their fixed costs, and prices from the pool. The aim was for the capacity market to be designed over several years and be operational by 2021.

Under energy-only markets investment decisions, including timing and type of generation assets, are supposed to be decided by firms. In contrast to this approach, in 2017 the new government announced the Renewable Electricity Program (REP) to implement a policy of administratively-determined type and amount of investment via a number of procurement rounds of wind and solar projects, based on a competitive auction process. These projects were procured under long-term contracts (LTCs)[1] with the AESO and are required to participate in the Alberta spot market. They are compensated by AESO (and ultimately rate payers) through a contract for difference mechanism.

The newly-elected government, in 2019, cancelled the capacity market that had been scheduled to begin shortly and rolled back a number of other proposed changes to the energy-only market.

The next significant government intervention in the energy-only market came in the form of billion-dollar consumer subsidies and deferrals to cover a portion of the increase in electricity prices caused by excess profits over the 2021-2023 period. First, the government implemented a direct consumer subsidy (termed a “rebate”) from July 2022 to April 2023. This was financed by the province and was applicable to RRO and Contract households (about a 35% and 65% market share, respectively).

Second, the government established a cap on the RRO of $0.135 per kilowatt-hour (kWh) from January to March 2023. This cap was not applicable to Contract households. This cap was not a rebate, but rather a “loan,” with the difference between the cap and the actual RRO to be paid back by RRO users through a regulatory deferral account, both of which are discussed further below.

In the aftermath of unprecedented retail price increases, government subsidies, energy alerts, and impending (and actual) blackouts, the government asked AESO and the Market Surveillance Administrator (MSA) to provide it with recommendations as to whether, and how, to reform the energy-only market. In March 2024, the government directed AESO to implement a “Restructured Energy Market” (REM), which will be explored in Chapter 3.

In short, the dream of a reliable grid with lower prices never materialized. In its place, Albertans have lived through a nightmare of some of the highest prices and most volatility in the country, combined with an outsized proportion of the most extreme energy emergency alerts in North America.

What is to be done about this mess? To answer that question, we first need to look at how the grids of other provinces are structured.

Structure, Ownership, and Regulation

So, if that is the background to the electricity sector in Alberta, how does its political economy compare to the rest of the country? ***Table 2*** presents a high-level summary of the level and type of integration in the electricity sectors across provinces, the type of regulation and the predominant form of ownership, including by segment.

Most of the country looks very different to Alberta. The most common form of grid structure in Canada is a vertically-integrated, province-wide (or a large portion of the province), publicly-regulated Crown corporation. This holds true in five provinces: British Columbia (BC Hydro), Saskatchewan (Saskatchewan Power), Manitoba (Manitoba Hydro), Quebec (Hydro-Québec), New Brunswick (NB Hydro). Until privatization in the 1990s, Nova Scotia was also home to a Crown corporation, Nova Scotia Power. Even after privatization, the utility remains vertically-integrated and regulated, covering the whole of the province. In each of these six cases, all components — distribution, transmission, and generation are regulated.

Newfoundland for its part enjoys a traditional, but geographically modified, vertically-integrated model wherein two vertically-integrated utilities serve different geographic areas. In this case, one is public and the other private, but again, both are regulated.

Finally, PEI, Ontario, and Alberta do not have large fully-integrated utilities, but instead have variations on the theme of disintegration.

PEI has a private regulated distribution and transmission utility that imports about 70% of its electricity from other provinces. Ontario mostly has municipally-owned distribution utilities, one private-public transmission provider and a generation market where numerous players, including the Crown corporation with 50% market share, are guaranteed revenues either through economic regulation or LTCs.

Alberta and Ontario are similar in that both have a mostly unbundled system, with the exception of an integrated transmission and distribution utility for most of the northerly non-urban regions of each province (ATCO and Hydro One). In the cities, both provinces have mostly publicly-owned municipal distribution utilities.

It is important to note, based on the experience from the US process of restructuring there is evidence that the disintegration of generation from the distribution segment not only did not lead to lower consumer prices, flowing from the former (generation), but also resulted in efficiency losses from the latter (distribution).[2] This can be explained by the loss of economies of scope (the savings gained by producing two or more distinct goods or services). These losses in scope efficiencies, would have been most severe in Alberta because the deregulation process was designed to, and resulted in, the disintegration of the previous “Big Three” of TransAlta, EPCOR, and ATCO. The remaining distribution-only companies are likely less efficient as a result. Albertans are doubly prejudiced; price-gouged as a result of market power in the generation segment and also likely to have to pay higher distribution prices than if the companies had remained integrated.

Where Alberta differs from Ontario and the rest of the provinces is that it has a mostly private unregulated generation market — a critique of which is the core focus of this report. We are now getting to the rub.

***Table 2**: Electricity Sector Structure, Ownership, and Regulation by Province*

	Generation	Transmission	Distribution
AB	Various private & one public operator participate in wholesale market for dispatch & market revenues (no out-of-market revenues[1]), largest: **TransAlta**, **Capital**[2], **Heartland**[3], **Suncor**, **ENMAX**[4]	Various private regulated utilities, with **AltaLink** and **ATCO** being largest and some public regulated (Edmonton, Calgary, etc.)	Regulated municipally-owned distribution utilities in Calgary (**ENMAX**), Edmonton (**EPCOR**), Red Deer, Lethbridge, and Medicine Hat[5], and private utilities (**FortisAlberta** and **ATCO**) elsewhere
ON	One public Crown, Ontario Power Generation (**OPG**) (OPG[6] ≈50% market share) & various private operators participate in wholesale market for dispatch and market revenues; all receive out-of-market revenues[7], set by regulation (OPG) or provincial contracts (private)	Private/public regulated utility = **Hydro One**[8]	About 60 municipally-owned, regulated distribution utilities, including in **Toronto Hydro**, **Ottawa Hydro** and other large population centers, with **Hydro One** serving 1.4 million rural subscribers
PE	One public Crown (**PEI Energy**)[9], & two private companies operate wind farms	Private regulated utility (**Maritime Electric (Fortis)**)[10] in most of the Island, except a municipally-owned utility (**Summerside Electric**)[11]	
NB	Vertically-integrated, public regulated Crown (**NB Power**)		Three municipally-owned, regulated distribution utilities serving **Saint John**, **Edmundston** & **Perth-Andover**, with **NB Power** serving rest of province
SK	Vertically-integrated, almost province-wide, public regulated Crown (**SaskPower**)		Municipally-owned regulated distribution utilities in **Saskatoon** & **Swift Current**; with **SaskPower** serving rest of province
NS	Vertically-integrated, province-wide, private regulated utility (**Nova Scotia Power**)		
QC	Vertically-integrated, province-wide, public regulated Crown (**Hydro-Québec**)		
NL	Two vertically-integrated operators serving different geographic (franchise) areas: public regulated Crown (**NL Hydro**) in Labrador and parts of Newfoundland; private regulated utility (**NL Power (Fortis)**) in other parts		
MB	Vertically-integrated, province-wide, public regulated Crown (**Manitoba Hydro**)		
BC	Two vertically-integrated operators serve different geographic (franchise) areas: public regulated Crown (**BC Hydro**) serves most of province; private regulated utility (**FortisBC**) serves south-central BC (Kelowna, etc.)		

Notes: 1) One exception is the generation assets awarded under the REP where the province instituted a contract for difference mechanism in relation to the “strike price” set via the REP auction and the pool price. 2) Capital Power includes the now privatized generation assets of EPCOR. 3) TransAlta announced in 2023 that it had acquired Heartland, which would become effective in 2024. 4) ENMAX is municipally-owned. 5) Medicine Hat also owns a generation plant capable of meeting its needs and exporting to the Alberta Interconnected Electric System, of which it is not part. 6) OPG is the generation segment successor Crown to the previously vertically-integrated Ontario Hydro that was unbundled in preparation for 2002 electricity reforms. 7) This is for a contract for difference mechanism between the regulated or contracted price (strike price) and market price. 8) Hydro One is the transmission and distribution segment successor to Ontario Hydro, it remains 47.2% owned by the province. 9) PEI Energy also owns sub-sea PEI-NB cable interconnection. 10) Maritime Electric also owns some limited generation assets. 11) Summerside Electric also owns one generation plant.

CHAPTER 2

Sector Performance During Deregulation

Started in 2001, Alberta's electricity deregulation and increasing privatization has been a costly experiment that has increased prices and volatility, reduced reliability and led to the lowest union rates in the country.

Higher Prices Add $24 Billion to Consumer Bills

ALBERTANS HAVE BEEN OVERPAYING for electricity since the beginning of deregulation in 2001. To show this, we first present the price data below, then we calculate Alberta's electricity system costs. This analysis demonstrates that since 2001, Albertans have paid about $24 billion more for their electricity than if they had paid the same prices as other Canadians.

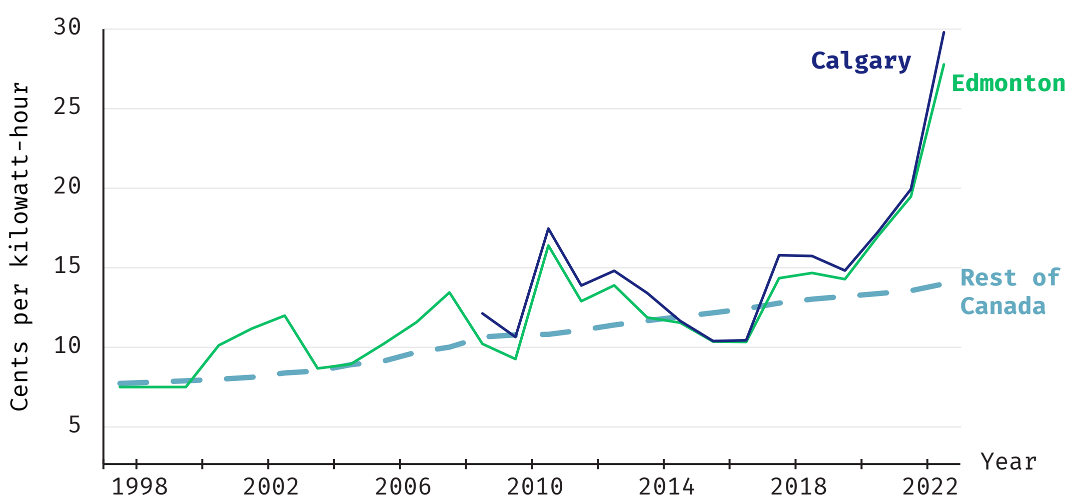
We present two sets of long-run data for "all in" prices for residential users[3], one on price levels[4] and the other on price changes[5]. ***Figure 11*** shows the evolution of residential prices from 1998 to 2023. During the pre-deregulation years of 1998-2001, prices in Edmonton were similar to the average of the other provinces, which we refer to as the "rest of Canada." Over the 2001-2008 period, prices in Edmonton ($0.11/kWh) were already higher than the rest of Canada's average ($0.09/kWh). During the 2009-2023 period, prices in Edmonton and Calgary, at $0.15 and $0.14/kWh, were respectively higher than the rest of Canada's average of $0.12/kWh. Figure 11 also shows that prices in the Alberta cities were much more volatile, with standard deviations for 2009-2023 being much higher than the rest of Canada's average.

To highlight the price index and volatility performance before and after deregulation, ***Figure 12*** (next page) sets residential electricity indices to 100 in each of 1Q1981 and 1Q2001. This shows that relative to 1Q1981, residential prices in Alberta increased 0.85% above the national average. However, over the course of the deregulation period, the Alberta electricity residential CPI increased by an average of 4.70% per year for the 1Q2001-3Q2024 period, well above the 2.90% for Canada as a whole. The difference is what matters here: it nearly doubled to 1.8% compared to the pre-deregulation period.

FIGURE 11: *ELECTRICITY PRICES FOR RESIDENTIAL USERS*

Source: Hydro-Québec (2023 and previous), Author's calculations.

Note: Assumes 750 kilowatt-hours (kWh)/month consumption, including generation, distribution, & other charges, excluding taxes.



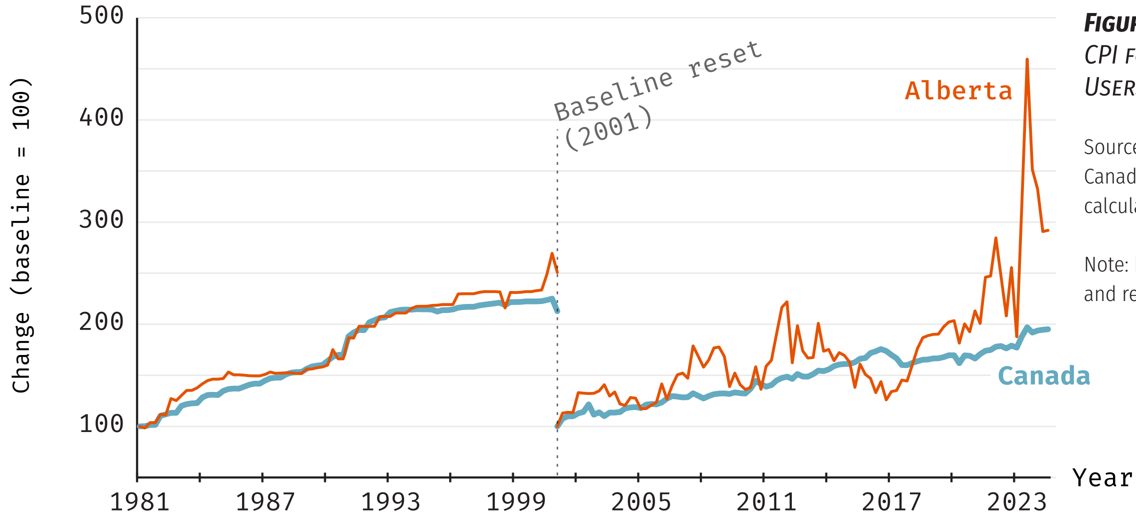


***Figure 12**: Electricity CPI for Residential Users, 1Q1981–3Q2024*

Source: Statistics Canada (2024i), Author's calculations.

Note: Index set 1981= 100 and reset 2001 = 100.

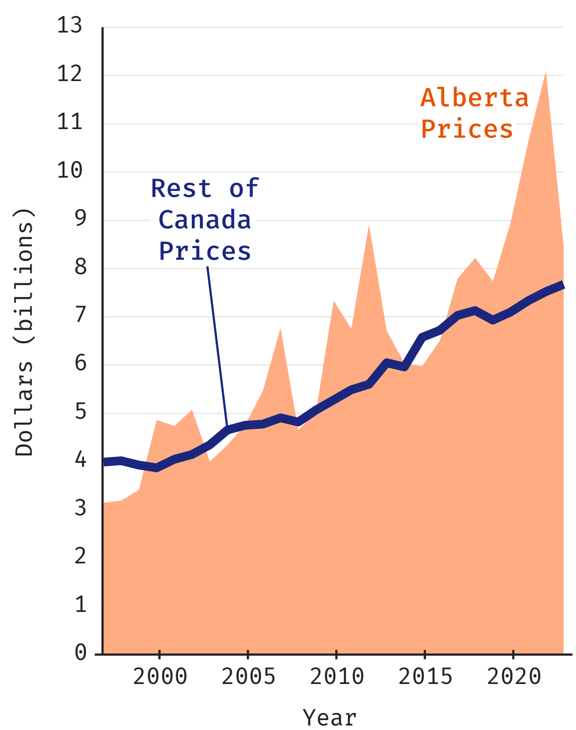
Figure 12 also shows the volatility of residential prices in Alberta increased, from being less than two times above that of Canada during the pre-deregulation period, to being more than five times higher during the deregulation period.

Having looked at price levels and changes in CPI for residential users, we now calculate Alberta electricity system costs with the objective of calculating how much more Albertans have paid due to these higher prices.

Figure 13 presents Alberta's electricity system costs from 1998 to 2024. System costs are a measure of the cost of the province's electricity system to all domestic consumers, including residential, industrial, commercial, and agricultural users. Other examples of system cost estimates include Bishop et al (2020) for nine provinces over the 2014-2018 period, and MSP (2023, 2024) estimates of Ontario's system costs for the 2004-2023 period.

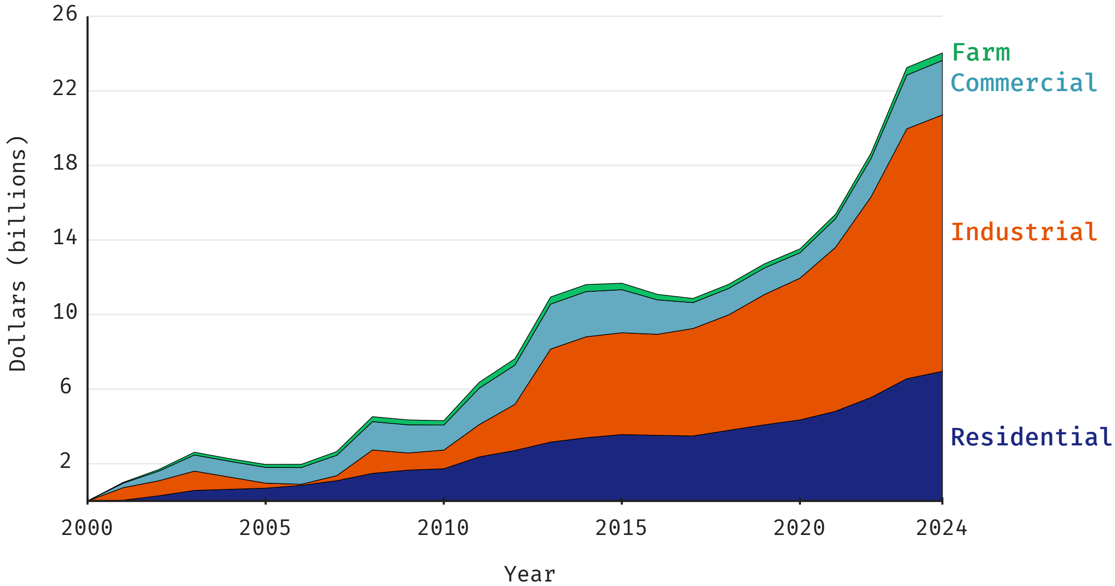
Figure 13 presents two system cost estimates for Alberta. One is based on the retail prices faced by Alberta consumers over the 1998-2024 period.[6] The other keeps all other Alberta-specific variables the same but instead of using Alberta prices, it applies the average retail prices faced by the rest of Canada.[7] On a year-by-year basis, the difference between the two estimates is how much more or less Alberta electricity consumers paid relative to what they would have paid had they faced the same prices as other Canadians.

***Figure 13**: Alberta System Costs, with Alberta prices and Rest of Canada prices, 2001-2024*



Source: Hydro-Quebec (2023 and previous), Bishop et al (2020), AUC (2024a), Statistics Canada (2024j), Author's calculations.

***Figure 14**: Cumulative difference between Alberta System Costs, with Alberta prices versus Rest of Canada prices, by type of consumer, 2001-2024*



Source: Hydro-Quebec (2023 and previous), Bishop et al (2020), AUC (2024a), Statistics Canada (2024j), Author's calculations.

Figure 13 looks similar to Figures 11 and 12, with a generally upward trend in Alberta system costs, calculated with both Alberta prices and Rest of Canada prices, with the former being much more volatile than the latter.

From the beginning of deregulation in 2001 to 2024, Alberta system costs with Alberta prices totalled approximately $162 billion. In contrast, Alberta system costs with Rest of Canada prices were around $138 billion. **Albertans hence paid about $24 billion more over the 24 year deregulation period than if they had faced the same prices as other Canadians. In inflation-adjusted 2024 constant dollars, those totals are approximately $206 and $177 billion respectively, so the extra costs system-wide Albertans had to pay were approximately $29 billion.**[8]

Figure 14 provides the cumulative differences over the 2001-2024 period between the two system cost estimates, broken down by type of user. Consistent with Figure 13, the cumulative total is approximately $24 billion.

Figure 14 shows that residential consumers paid about $7.0 billion more during the deregulation period. **That is an average of about $205 per year per household for each of the 24 years, or just under $5,000 for the whole period.** Industrial users, which make up the majority of usage in Alberta, paid about $13.8 billion more during the deregulation period. Commercial and farm users paid $2.9 and $0.4 billion more, respectively.

Price Volatility Hurts Low-Income Households

In addition to introducing *wholesale* competition, Alberta also introduced competition in the *retailing* of electricity. Part of this reform included requiring designated incumbent distribution companies to maintain a "default" that would apply to consumers in their service territory that were not eligible for or did not opt into a contract, the "RRO."[9]

There are a myriad of contract offers that range from variable to fixed rates, including from 1- to 5-year terms. This requires "active" consumers who have the time, sophistication, motivation, and credit-worthiness to select a contract that suits their needs and to maintain vigilance on a going forward basis, including switching retailers as necessary. This is what economists refer to as "search" and "switching," and the costs can be significant.

Competitive retail also means that at any one time, many consumers are paying different prices for the same electricity services, depending on whether they are on the RRO. They could also potentially make changes part-way through an ongoing contract. During volatile price periods, this is likely to have an effect on the Alberta electricity CPI and the Hydro-Quebec price numbers as the respective energy components for residential users appear to only track changes in the RRO over time but excludes the majority of residential customers that are on contracts. This is an analytical challenge because it does not allow for an accurate assessment of the change in effective prices paid by households over time. This is a data gap that should be closed by the Government of Alberta. In the meantime, this report provides the first estimates of the average weighted contract prices and, based on the number of RRO vs. contract subscribers, the overall effective rate "RRO+contract."[10]

Figure 15 shows the evolution of the RRO, contract, and RRO+contract prices from 1Q2019 to 2Q2024. The estimates in Figure 15 do not take into account the consumer rebate and RRO deferral that were in effect during the period indicated therein. During the first half of this period, which corresponded with relatively stable prices, the RRO and contract prices were relatively similar, with the RRO price being slightly lower. However, during the second half of this period, during very volatile prices driven by price-gouging, it opened a large

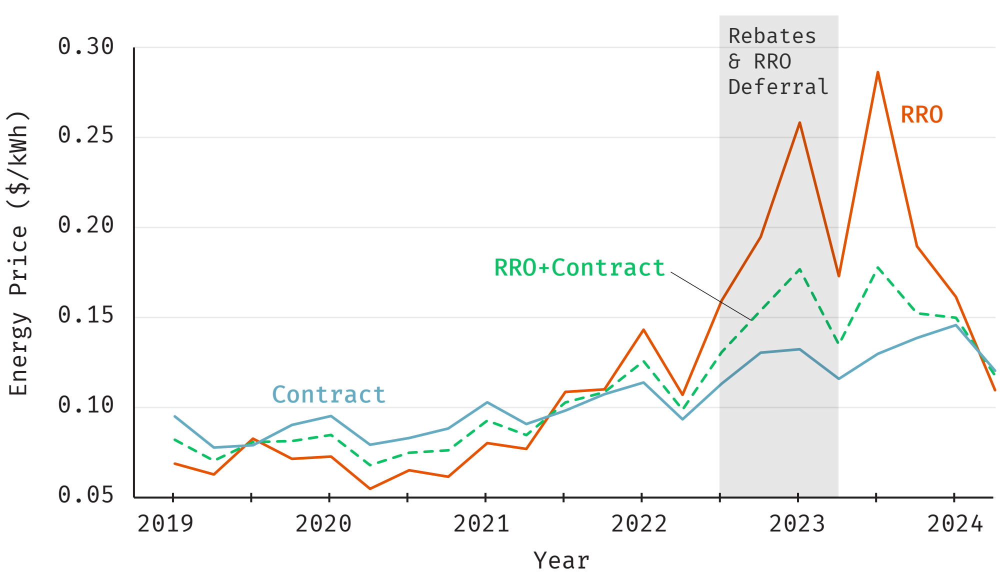


***Figure 15**: Comparison of RRO and Contract Prices*

Source: Author's calculations (2024).

difference between the RRO and contract prices, with the contract prices being significantly lower than RRO prices.

Being a "passive" or "disengaged" consumer, or one that did not have the credit rating to be eligible to apply for a contract, was extremely prejudicial during the second half of this period. These types of consumers ended up paying much higher prices for the same electricity than other households.

While no studies have been carried out in Alberta, research elsewhere indicates that the lowest-income and otherwise most vulnerable households bear the most cost. Studies in other countries have found that unemployment, lower educational attainment, and lower income are all associated with lower switching rates and that low-income households and marginalized communities pay systematically higher electricity prices than higher-income households.[11]

Based on the above studies and many others, we can say with confidence that lower-income and marginalized households in Alberta pay higher electricity prices than higher-income households under the competitive retail markets introduced in 2001.

This is exacerbated by the lack of targeted financial assistance program for low-income electricity in Alberta, unlike the Ontario Electricity Support Program and similar programs in the US.

Despite the absence of some data, ***Figure 16*** suggests lower-income Albertans pay higher and suffer more in the face of more volatile prices than other households. This figure tracks the ratio of Alberta to Canada electricity spending by household income groups (quintiles) from 2010 to 2021 (with 2018 and 2020 years interpolated).

The lowest quintile covers the bottom 20% of the households by income, the middle quintile covers the middle 20%, and the highest quintile covers the highest income 20%. Figure 16 shows that the average Alberta/Canada ratio for the lowest quintile is highest of all the quintiles, at around 1.1. This means that relative to other income classes, the lowest quintile in Alberta pays relatively the most. And their prices are the most volatile, with the highest standard deviation of 0.12.

It's not just higher prices that hurt low-income Albertans; volatility in prices is much harder to deal with at the lower end of the income ladder, harder to plan and budget for. But as we shall see in the next section, the fragilization of the grid is something that puts all Albertans at deadly risk, no matter how rich or poor.

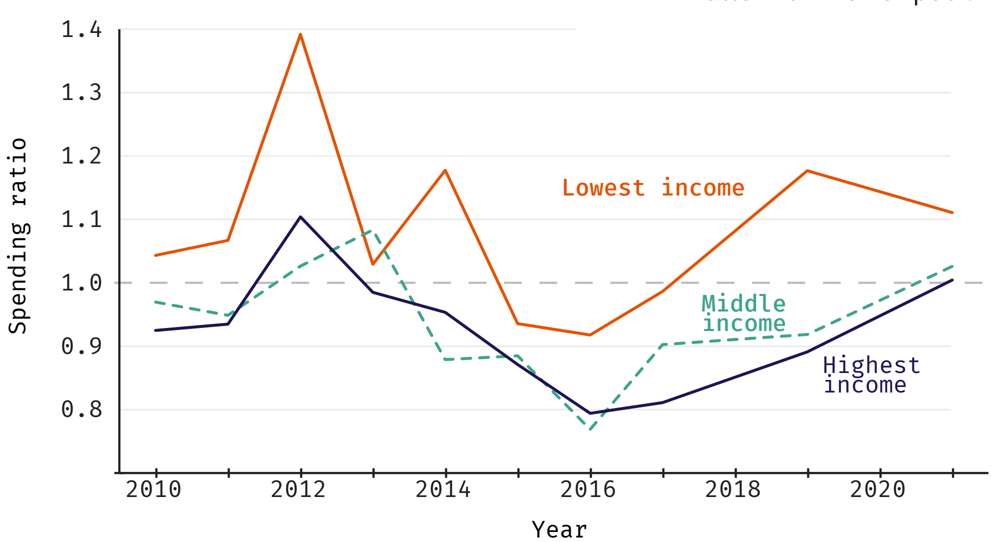


***Figure 16**: Ratio of Alberta/Canada Spending on Electricity, by Quintile*

Source: Statistics Canada, Author's calculations (2024).

Note: Value greater than one indicates higher spending relative to the Canadian average for that income quintile.

Reliability: North America's Most Fragile Grid

There are a number of different electricity system reliability metrics. One such metric is the Energy Emergency Alerts (EEA) rating of the North American Electric Reliability Corporation (NERC).

NERC describes three levels of EEA, from 1 to 3; the most severe is EEA3. An EEA3 is defined as an imminent or occurring interruption to firm load (a blackout), with the system operator unable to satisfy its contingency reserve requirements. To avoid a system blackout, grid operators may implement rolling planned outages, or "load shedding." Because this is such a severe event, grid operators must notify other NERC members when they declare EEA3s.

Figure 17 shows the totality of EEA3 alerts issued by NERC members, including in Alberta from 2006, when NERC was established, to April 2024. For context, Alberta accounts for less than 2% of the total NERC load.

Figure 17 also shows that due to a few isolated EEAs from 2006-2021 (of which one in 2013 was associated with a 200-megawatt (MW) load-shedding event), Alberta has become the NERC member with the most EEA3 events since January 2022. From January 2022 to April 2024, Alberta accounted for an astronomically high 33% of all EEA3 alerts (16 in total).

Figure 17: *EEA3 Alerts in Alberta and Rest of North America*

Source: AESO (2024d), NERC (2024 and previous), Author's calculations.

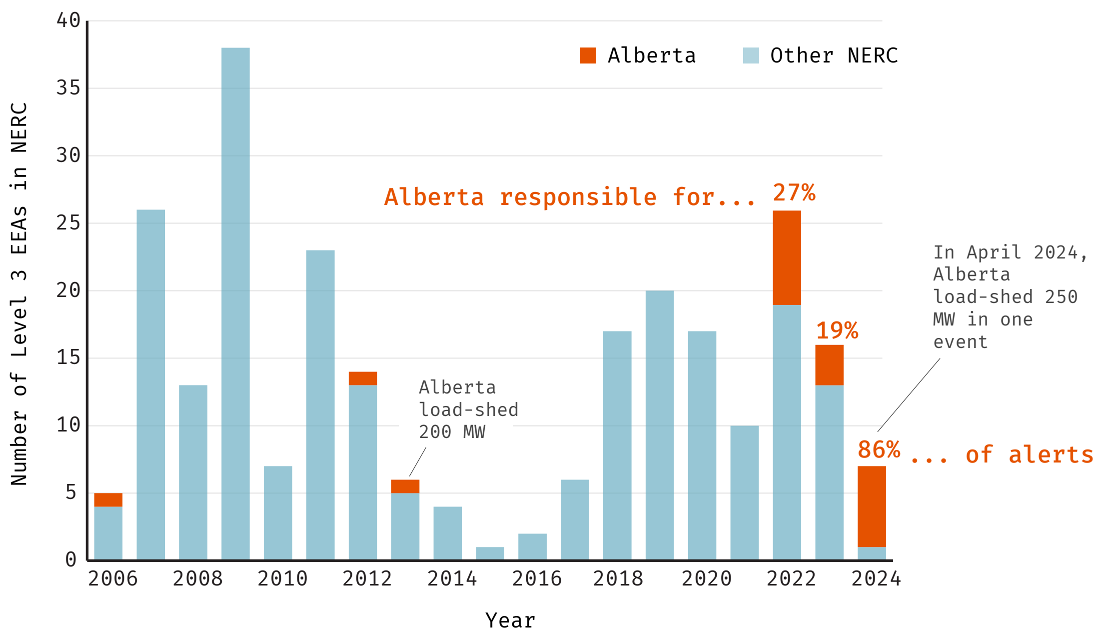
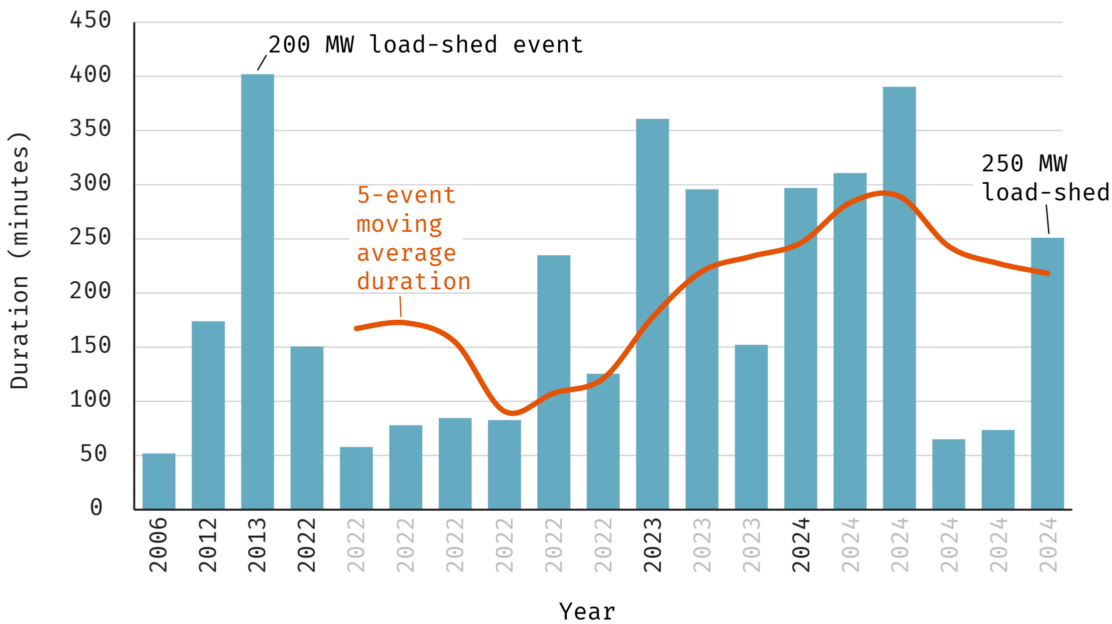


***FIGURE 18**: DURATION OF ALBERTA EEA3 ALERTS*



Source: AESO (2024d), Author's calculations.

Recall that Alberta accounts for less than 2% of the NERC load, which means that during that period it was more than **twenty times more likely to issue an EEA3 alert than other grids**, on average. One of those alerts, in April 2024, resulted in a 250 MW load-shedding event.

And not only has the frequency of EEA3s increased, but so has their duration. ***Figure 18*** shows the duration, in minutes, of all 19 of Alberta's EEA3 grid alerts. It reveals that on a 5-event moving average basis, Alberta's recent EEAs have had durations of between 200 to 300 minutes.

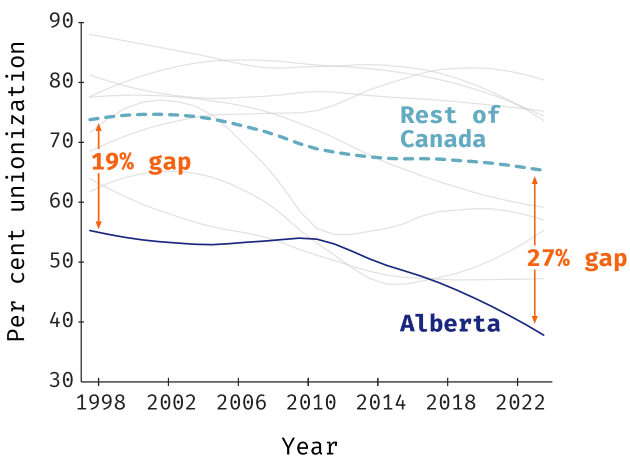
It is no exaggeration to declare Alberta's electricity grid to currently be the most fragile in North America when measured by the number of EEA3 alerts.

But it is not just the grid that has found itself in a precarious situation. The market fundamentalism that has led to this crisis has also, perhaps unsurprisingly, left workers in particular, electricity sector workers, less well off too.

Labour Outcomes

Alberta's electricity sector has traditionally had comparatively low union rates, which then declined even further during deregulation. ***Figure 19*** shows union rates have decreased both absolutely and relatively to the rest of Canada. During the late 1990s, unionization rates in Alberta were about 19 percentage points behind the rest of Canada. By the 2020s, that gap increased to 27%.

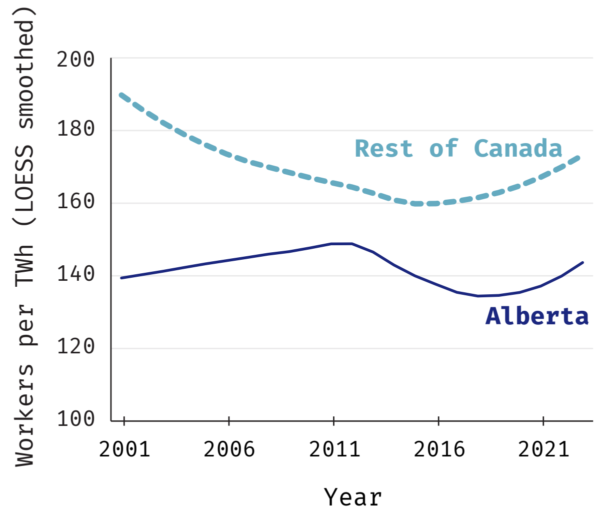
***Figure 19**: Per Cent of Unionization in Electricity Sector by Province*



Source: Statistics Canada (2024g), Author's calculations.

The electricity sector in Alberta has traditionally employed relatively fewer workers than the rest of Canada. ***Figure 20*** shows that on a per terawatt-hour (TWh) basis, Alberta's electricity sector employed an average of 141 workers/TWh over the deregulation period, significantly lower than the rest of Canada's average of about 169 workers/TWh.

***Figure 20**: Employment in the Electricity Sector, Alberta and Canada*



Source: Statistics Canada (2024e), Author's calculations.

This is because a public sector entity's goal is supposed to be optimal provision of a service rather than optimization of profit, particularly with a service as mission-critical to society as electricity. In principle, a public utility or regulated private utility—so long as adequately provisioned through democratic mandate—will simply hire the number of workers necessary for a task. This has a knock-on effect on health and safety too; worksites with too few, and often overworked, employees are not safe or healthy places to work at.

Treating the grid badly is treating workers badly, and much the same in reverse.

CHAPTER 3

What Is To Be Done? Re-Regulation Of Generation

Re-regulation of Alberta's electricity sector offers a low-risk path to a more affordable and reliable energy future for the province.

Regulation and Markets

THE ELECTRICITY SECTOR is unlike the rest of the economy. It is of strategic importance and therefore inherently imbued with the public interest. As a society we have established institutions to try to ensure it actually performs accordingly. Second, it is capital intensive, with long-lived assets that have relatively high fixed costs and low marginal costs. This set of cost characteristics resulted in the "natural monopoly" problem wherein the lowest cost operational option was a single supplier — a monopoly. But even high school economics teaches us that left to their own devices, relative to effectively competitive markets, monopolies will restrict output and increase prices. This is why economic regulation was "invented." To control monopolies and ensure that the operational cost savings were equitably shared with consumers in the form of lower prices.

The importance and longevity of the regulated utility as an institutional innovation due to its relative superiority, when applied to private utilities, aligns private enterprise with the public interest from efficiency and equity perspectives. As discussed further below, it generally results in lower retail prices. There are many reasons why this has been the practice over the last century.

Figure 21 shows one of these reasons, the cost of capital of regulated utilities versus those of merchant independent power producers (IPPs) that operate in competitive wholesale markets. We have shown above that the energy-only markets are designed for their respective prices and investment to be cyclical. This is in fact a general feature of deregulated relative to regulated utilities. From a financing perspective, banks and other institutions will assign a higher risk to merchant IPPs to take into account the uncertainty over the amount, and price of the generation output, received by

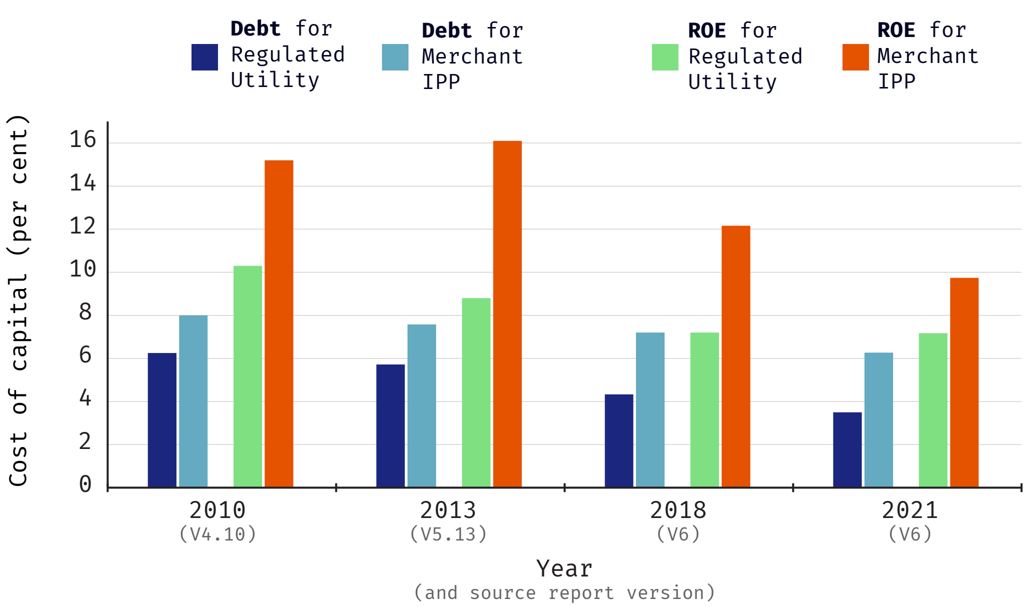


***FIGURE 21**: DEBT AND RETURN ON EQUITY RATES FOR UTILITIES & IPPS, USA*

Note: ROE = Return on Equity

Sources: Environmental Protection Agency (2021 and previous), Author's calculations.

merchant IPPs. Banks want to ensure that merchant IPPs have sufficient revenues in the future to repay their loans. This is in stark contrast to the regulated utility where the revenue stream is much less risky.

Based on financial research and benchmarking, and for use in their modelling work, the Environmental Protection Agency in the US calculates the two components that make up a firm's cost of capital: the cost of debt and equity, for regulated utilities and merchant IPPs, from 2010 to 2021. In every instance, the cost of debt and equity (the return on equity, or ROE) is lower for regulated utilities in the US relative to merchant IPPs, averaging 2.3% and 4.9% respectively. For example, using a 55%/45% debt-to-equity weighting, shows that the weighted average cost of capital (WACC) was on average 3.5% lower for regulated utilities. Lower financing cost will translate to lower retail prices.

The idea that the generation segment never was or was no longer a natural monopoly and hence should be subject to competition, was an idea that gained steam in the 1980s and peaked in the 1990s in North America. This was when Alberta and Ontario in Canada and a minority of US states started the long and costly, legal, operational and institution-building process to deregulate that segment.[12] The theory was that, freed from regulated profits, competitors would have the incentive to lower operational costs and that the competitive process would protect consumers by ensuring that those lower costs were passed on to consumers in the form of lower prices. Win-win, in theory.

In the real world of imperfect regulatory constructs and markets designed and administered by imperfect humans, what is the actual practical experience of regulation versus competition? For Alberta, at least, higher prices and volatility, reduced reliability, and excess profits.

Deregulation was also supposed to boost investment relative to the regulation. Alberta's electricity sector has traditionally had comparatively low investment, but deregulation has not changed that.

Figure 22 shows investment in electric power from 1981 to 2022 for Alberta and the rest of Canada relative to respective Gross Domestic Product (GDP). During the pre-deregulation period from 1981 to 2000, Alberta's electricity investment was 0.20% points below the rest of Canada. That underperformance did not materially improve during the deregulation period, when Alberta averaged 0.16% below the rest of Canada's average. Relatively low investment in Alberta is not a regulation versus deregulation problem; it is a public versus private investment problem.

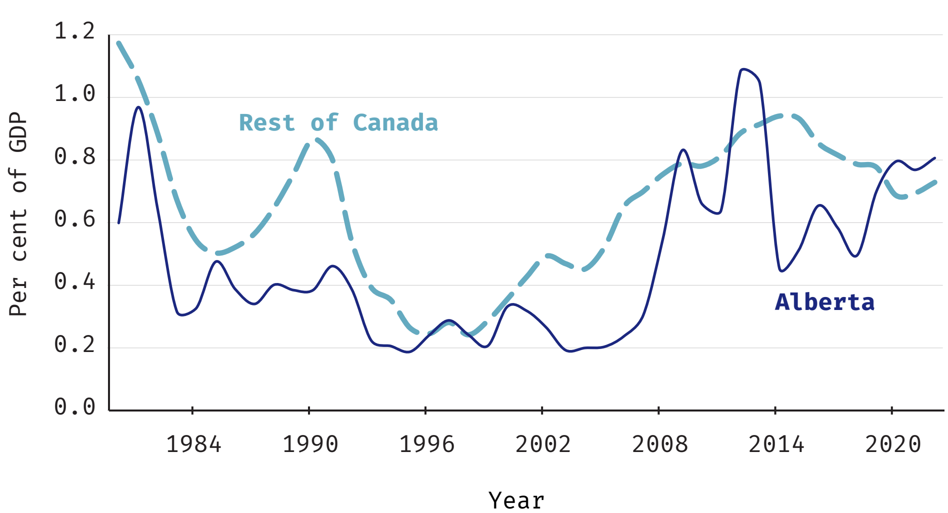


***Figure 22**: Electricity Investment, Alberta, and Rest of Canada*

Source: Statistics Canada (2024a), Author's calculation.

Alberta's Small and Concentrated Market

Both regulated and deregulated electricity utilities require high levels of expertise in high-functioning institutional environments to perform well. Alberta has demonstrated the capacity to administer either approach. But size and structure matter, and Alberta's relatively small market size reduces the potential theoretical benefits of competition relative to regulation.

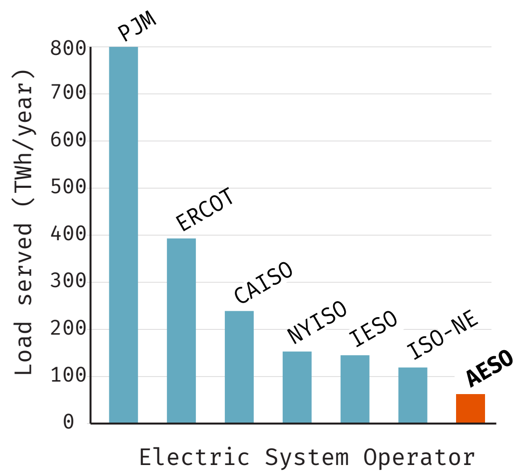
This disadvantage is further exacerbated due to enduring the highly concentrated nature of the Alberta generation market. Addressing these limiting structural deficiencies will merely get Alberta close to where most of the rest of the markets are in the US. The US evidence shows that even under these circumstances, prices are higher, and market power persists. This means that most of the reform-oriented market "tweaks" to the existing system, that we will discuss in the section below on Restructured Electricity Markets, are unlikely to result in improved performance relative to regulation.

Figure 23 shows the size in TWh per year of the Regional Transmission Organizations and Independent System Operators (ISOs). It includes only majority restructured provinces and states[13] and shows that Alberta has the smallest such generation market, by far.

The theory of free trade is that the larger the market, the larger the gains are from the exchange of any commodity, including electricity. Thus, the gains from a deregulated market in Alberta are structurally constrained by its relatively modest size. No amount of market reform can overcome this limitation.

Further, larger generation markets are likely to be less concentrated than smaller markets. This is

Figure 23*: Size of Deregulated ISOs/Markets in North America*



Sources: FERC (2024), AESO (2024a), Author's calculations.

why the "market-making" policy decisions prior to market opening are critical, because of their long-term effects. Market advocates in the 1990s were aware that simply carrying forward with the predominant vertically-integrated market structure would not result in effective competition in the generation segment as incumbents would have the incentive to provide unequal access to their downstream transmission and distribution segments, thus stifling entry or raising rival's costs. That is why the consensus emerged that the generation segment had to be unbundled from the rest of the corporate structure.

But there was no consensus in Alberta as to *how* to unbundle. There were basically three broad options. Each had their own advantages and disadvantages, depending on the size and pre-existing structure of the market.

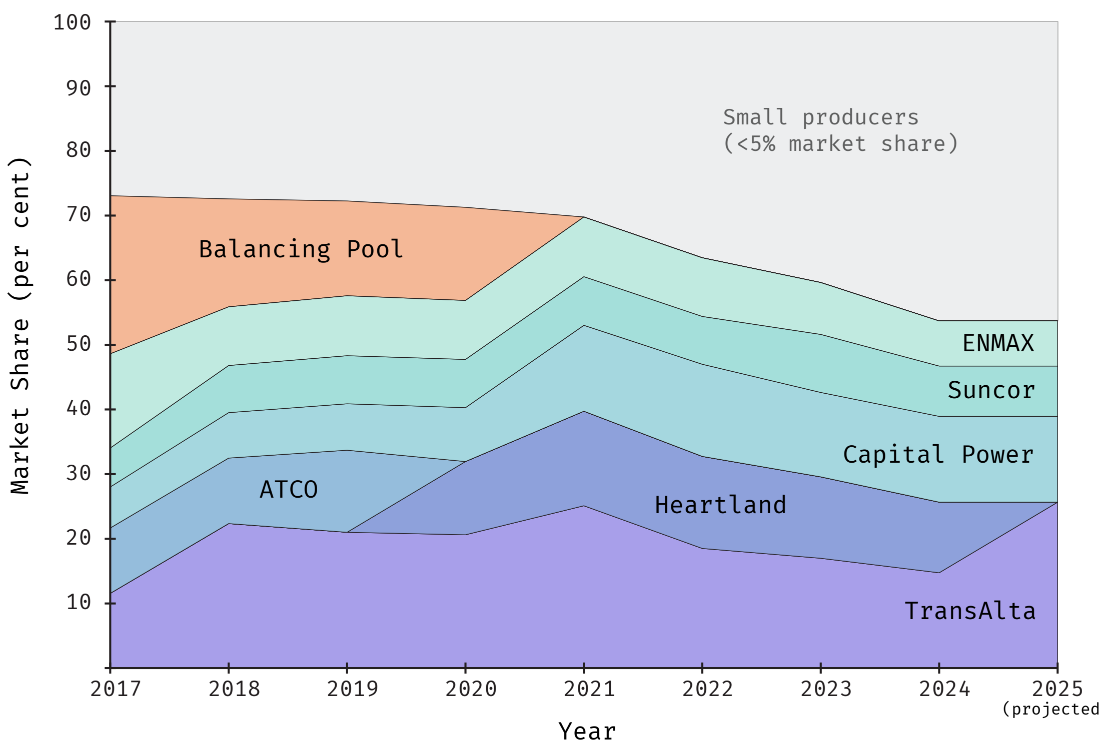
One was to mandate legal and operational divestiture of the generation portfolio, as a whole. Another variation was to require an "atomization" of the portfolio, dividing it into three, four or more, with each being sold to different owners. A third option was to require a temporary or "virtual" forms of divestiture that did not require a change in ownership. An overriding consideration was whether policy-makers would include restrictions on buyers of divested assets. A whole portfolio divestment was probably appropriate in a large market of many vertically-integrated utilities because that would result in an equal number of generation competitors compared to a relatively less concentrated market. That was not the case in Alberta, where just three companies controlled about 90% of the generation market.

The government of the day, however, was opposed to mandatory divestiture and therefore a combination of options two and three were adopted. These were the PPAs whereby the government allowed the "Big Three" to maintain legal ownership of the assets. This also allowed them the right to continue to receive payments based on a simplified form of regulation but auctioned the operational control of their generation assets for 20 years in a number of bundles. With that operational control came the right of the buyers of the PPAs to keep the margin between payments that had to be made to the owners and what the buyers could make in the wholesale market. The PPAs were to be in place for 20 years, after which it was assumed that sufficient new entry would have occurred to have diluted the market power of the original Big Three.[14]

Figure 24 shows just how concentrated the Alberta generation market remains after more than 20 years. It shows the actual "offer control" of the generation entities that have more than 5% of market share. Data for 2017 to 2024 are actuals and 2025 is a projection, as discussed below. In 2017, when the Balancing Pool was still administering some of the returned PPAs and was mandated to offer them on a competitive basis, the other large generators (TransAlta, ENMAX, Capital Power, ATCO, and Heartland) accounted for 50% of the market share. In the period to 2021, this figure increased to about 70% as the PPAs expired. ATCO's assets were also acquired by Heartland during that period. Some smaller players have entered since then and some assets have been retired, so by 1Q2024 the market share of the "Big Five" declined to 54%.

***Figure 24**: Share of Offer Control of Participants with more than 5 Per Cent Share, Alberta*

Sources: MSA (2024), Author's calculations.



It is possible, however, that the "Big Five" will soon become the "Big Four" because the largest operator, TransAlta, announced in 2023 that it had acquired the third largest operator, Heartland (subject to regulatory approval). That is why in Figure 24 the year 2025 is a projection. Based on federal/provincial jurisdiction, such an acquisition is being reviewed by the federal Competition Bureau (2024), which is expected to issue a decision in the second half of 2024.

On just about every metric predicted to improve in a deregulated electricity market, from lower prices to more market entrants and greater competition, the deregulation project has been an abject failure. The opposite of every stated goal has instead prevailed.

Market Power, Excess Profits and Price Gouging

One of the main objectives of economic regulation is to protect consumers from the exercise of corporate market power. It does this by controlling profits and thereby indirectly controlling prices. The promoters of deregulation wanted to "disrupt" this carefully-crafted balance, arguing that it would no longer be necessary to control profits because competition in the newly-created generation market would be sufficient to protect consumers.

Generation markets, especially small and concentrated ones such Alberta's, have not cooperated with these rosy predictions. The problem has been, and will continue to be, market power: the ability of one or more firms to raise prices above the competitive equilibrium price of marginal cost.

As we highlight below, a recent Alberta price spike experience is directly related to the exercise of unregulated market power that has resulted in large monetary transfers from consumers to corporations.

Before diving into the Alberta analysis, it is important to highlight that while the exercise of market power has recently been egregious in the province, it is not unique. The results of multiple studies have shown it is a feature of "deregulated" markets.

For example, a recent careful analysis found that in the US, generation costs decreased and wholesale prices increased in deregulated markets.[15] Higher wholesale prices explain a substantial portion of the increase in retail prices. How can this be? Because wholesale margins increased in deregulated markets, indicating firms were able to set prices above marginal cost, as a result of limited competition and market power.

In deregulated markets, the theory worked well on the producer side (i.e., increased efficiency gains) but did not work well with respect to the societal function of competition, which is that consumers should also benefit from those efficiency gains. If those are macro results over 20 years for an entire country, our own analysis presented for Alberta is indicative of worse results for consumers and taxpayers. It is not only likely that producers captured most of the efficiency gains from the deregulated market in Alberta, but that during the last few years they had very large excess profits to the detriment of consumers.

The most recent peer-reviewed study[16] that looked at the termination of the PPAs and their effect on the market contains useful insight on market power and the effect it has had on prices.

The authors note that the return of the PPAs to their original owners lead to a "large increase in market concentration," highlighting that:

> We find that the exercise of market power can explain two-thirds of the 120% increase in average peak hour prices between 2020 and 2021. The sizable increase in market power coincides with the expiry of the PPAs and resulted in a large transfer of payments from consumers to producers.

We note that this study only includes analysis to the end of 2021, which was the beginning of the upswing in the increase in prices that would peak in the 2022-2023 period. Given the relative stability in market shares and other market conditions, the study's findings on market power are likely applicable for the years after 2021, as noted:

> Further, our analysis serves as a cautionary tale of what happens when market power mitigation policies are removed in a concentrated wholesale market. In particular, as a small market with limited interconnections to other grids, Alberta's market is likely to remain prone to periods of elevated market power for the foreseeable future.

In the rest of this section, we present analysis to show how market power continued to be exerted in Alberta. In the first part, we replicate and build off the recent MSA analysis that calculates whether the level of excess profits was required to make a contribution to fixed costs, an issue we first discussed in Chapter 1. The authors of the above-referenced study posited this possibility in 2021:

> It is possible that the elevated market power observed in Alberta's "energy-only" market in certain years is required to permit fixed-cost recovery, particularly after several years of low prices when the PPA units were offered in at marginal cost.

Figure 25 shows the net revenues and implied WACC of a hypothetical Gas Combined Cycle generator based on the actual observed prices.[17] Based on financial benchmarks, the MSA classifies WACCs of 12.5% and 8.5% as "Very High" and "Medium." Figure 25 shows a section of the price and profit "cycle" discussed in Chapter 1. However, unlike the idealized model of competitive markets where, on average, profits are "Medium," in Figure 25, we see that profit peaks in the 2021-2023 period are so high that they more than make up for lower profits of the 2014-2017 period. The figure illustrates both the volatile and excessive nature (far above a typical WACC) of profits for the hypothetical Alberta Gas Combined Cycle generator.

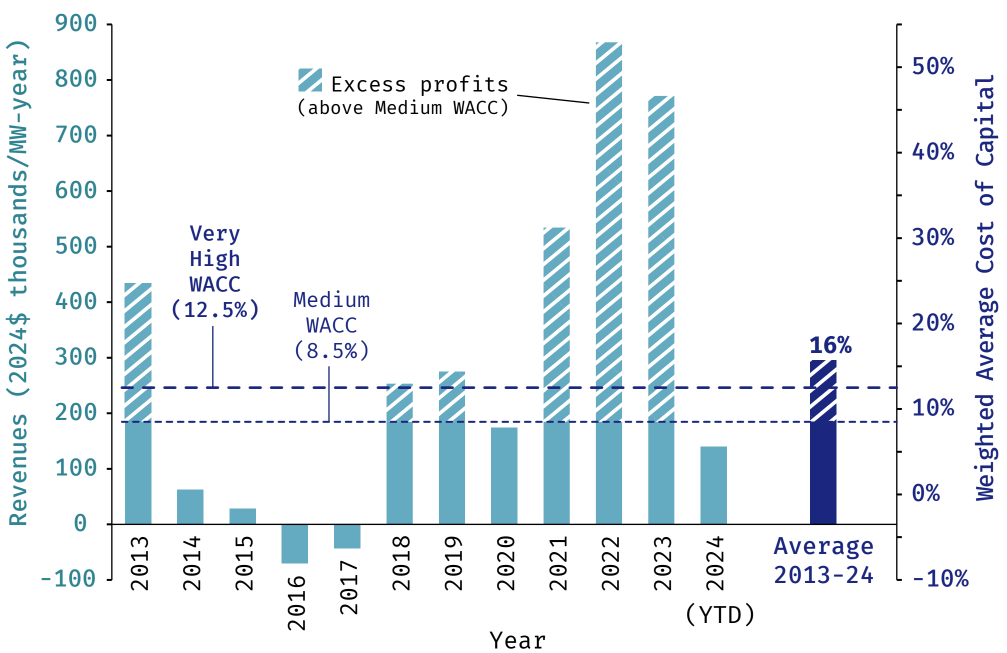


***Figure 25**: Revenues and WACC of Hypothetical Gas Combined Cycle Operator in Alberta*

Sources: MSA (2024), Author's calculations.

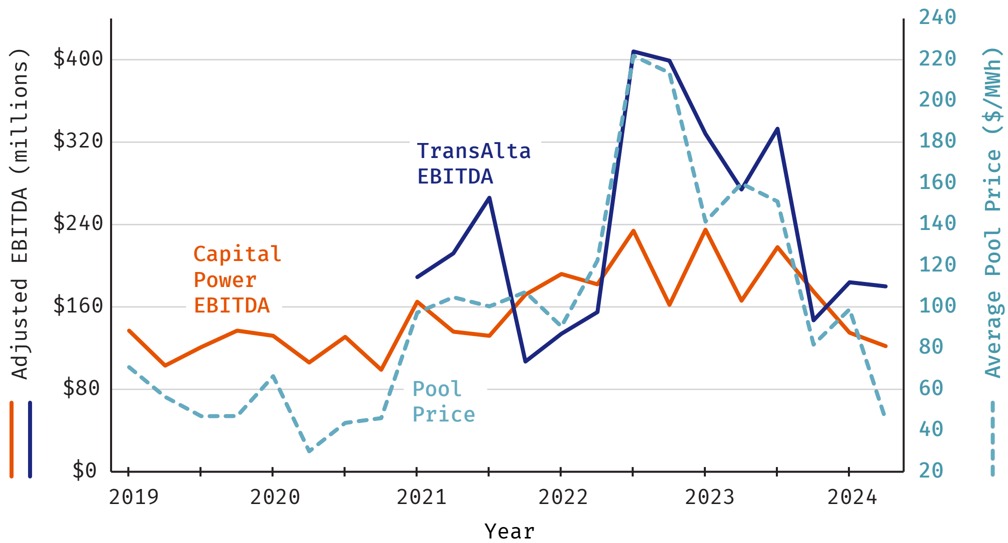


***Figure 26**: TransAlta and Capital Power EBITDA and AESO Pool Price*

Source: TransAlta (2024), Capital Power (2024), Author's calculations.

Over the dozen-year cycle (2013 to 2024YTD), profits were very high, with an average WACC of 16.0%.[18]

In this regard the MSA noted the following:

> Capital cost recovery takes place over many years, and requires a stream of net revenues over the lifespan of the generating asset. A hypothetical combined cycle or gas peaker generator built in 2013 would have received total net revenues that outpaced its capital financing costs by 2021 or 2022, depending on the assumed cost of capital.
>
> By the end of Q1 2024 a combined cycle generator financed with a low WACC would have recovered 80% of its capital costs over the preceding 11 years, well in advance of its 30-year unit life.

This is evidence of profit-driven price-gouging resulting from the exertion of unregulated market power. It shows a failure of policy-makers to protect consumers by allowing unlimited profits in the generation segment.

Another approach is possible, one that properly balances the interests of consumers and the corporations that serve them — one that promotes predictability and regulates profits to be no greater than "medium," and is designed to ensure that there are no "large transfer of payments from consumers to producers."

In the second part, we undertake a financial analysis of two of the large generation companies to see how their earnings have reflected those high hypothetical profits modelled by the MSA.

Figure 26 tracks Alberta's pool price and the corporate earnings of TransAlta and Capital Power, the first and second largest generation entities in Alberta.[19] As a result of tight conditions and the exercise of market power, prices spiked well beyond those that would have been necessary to pass on higher input costs. The proof? Higher earnings that track higher wholesale prices, as presented in Figure 26, shows the average Alberta generation wholesale pool price and adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA).

Figure 26 shows that both the pool price and adjusted EBITDA increased dramatically starting the third quarter of 2022 and then remain relatively high for five quarters, until the fourth quarter of 2023. This quarterly "micro" view mirrors the annual "macro" view of higher earnings in the 2021-2023 period.

Figure 27 shows the same information as in Figure 26, except from an annual perspective, to match the annual analysis presented in Figure 25. To include all the data, it sets an index of 100 for the 2021 annual average. It shows that after pool prices spiked in 2021, adjusted EBITDA for Capital Power did as well. Both Capital Power and TransAlta further increased their adjusted EBITDA in 2022 and 2023 to reflect much higher pool prices. Earnings only started to decline from their record levels in 1Q2024.

We know from Chapter 2 that prices in regulated markets in other provinces increased somewhat during the 2021-2023 period, but not as dramatically as those in Alberta. Even other provinces that have a relatively high natural gas generation, such as Nova Scotia, New Brunswick and Saskatchewan had increases that were much more moderate than those in Alberta. Why is this? It is because a regulated market would have allowed firms to pass on to the consumers the higher costs of natural gas during this period. But *no more* than that. Earnings would have been stable because they are just the difference between revenues and the cost of inputs, such as natural gas.

But what we saw in Alberta was an unrestricted exercise of market power that allowed profit-driven price-gouging that resulted in large financial transfers from consumers to firms. All facilitated by Alberta's small and concentrated deregulated generation market.

Regulation Has a Proven Record of Growth

In addition to the traditional concerns in regard to providing affordable and reliable electricity, an additional recent challenge is that of a new era of electrification as a result of the challenge of climate change. Electrification in the 21st century means the displacement of energy services currently powered by medium or high-emitting combustion by those powered by low or zero emitting electricity, which must happen alongside new generation for novel sources of demand for electricity such as data centres for artificial intelligence.

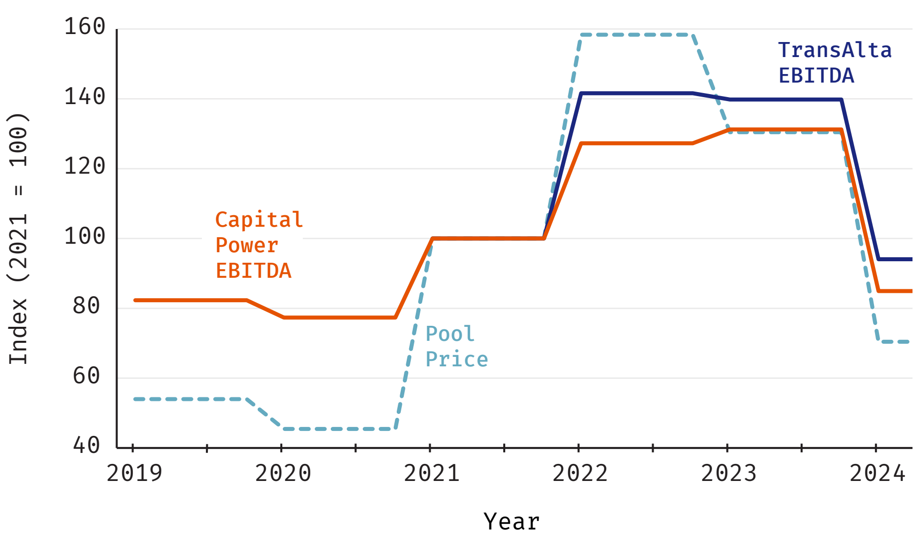
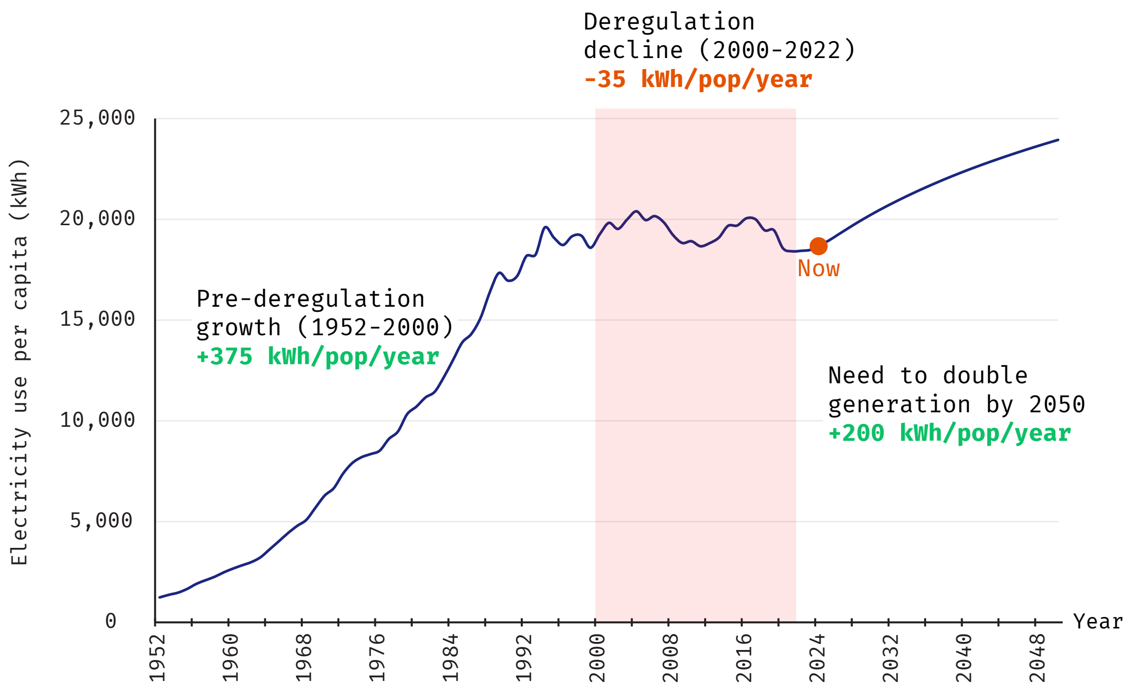


***Figure 27**: Index of TransAlta, Capital Power EBITDA and AESO Pool Price*

Source: TransAlta (2024), Capital (2024), Author's calculations.

Figure 28: *Long-Term Population-Adjusted Alberta Generation*



Source: AUC (2024a), Author's research and calculations

This is not the first era of electrification. As Chapter 1 described and as ***Figure 28*** shows, the first 100 years of electrification, from the invention of electricity to about the 1970s, involved a form of energy switching (such as from gas or oil lighting to electric lighting, from muscle power to wash clothes to an electric washing machine, etc.). Later on, there were sources of new demand such as televisions, computers, and telecommunications.

Figure 28 shows that from the early 1950s to the beginning of deregulation in 2000, the amount of electricity produced in Alberta increased by about *fifty* times. On a population-adjusted per capita basis, it increased by an average of 375 kWh/person per year for nearly fifty years. In stark contrast, population-adjusted electricity generation has decreased since deregulation, at -35 kWh/person per year.

This decrease in the rate of electrification is not unique to Alberta. All provinces and most high-income industrialized countries have seen such decreases, associated with the organic growth of electrification hitting a "wall" where it no longer made short-term financial sense to further electrify. This could include replacing internal combustion engines with electric vehicles in combination with increasing efficiency and regulations such as incandescent lights replaced by LED lights, etc.

We are now embarking on a second era of electrification, and models suggest a doubling of generation will be necessary by 2050. This will likely be driven in the short and medium term by policy (from carbon pricing, industrial policy, etc.) and regulation (e.g., efficiency requirements, banning the sale of new Internal Combustion Engine vehicles, and similar).

Figure 28 shows the growth of electricity generation in Alberta based on population projections and a doubling of generation by 2050. It illustrates that to reach such an objective, generation would have to grow to about 200 kWh/person per year for the next 25 years. That is minor compared to the perspective of the previous era of electrification (375 kWh/person), but still a daunting challenge relative to the decline in per capita demand of the last two decades (-35 kWh/person).

From a policy perspective, if we care about electrification, how would we assess deregulation and regulation?

It is not that deregulation generally, and Alberta's cyclical energy-only market specifically, cannot in theory achieve a doubling of the grid in 25 years, but the record matters.

Deregulation has not demonstrated that it has the structural capacity to facilitate 200 kWh per person per year in growth for decades at a time.

In contrast, regulated markets were designed specifically to facilitate growth faster than markets left to their own devices, and have demonstrated in Alberta and elsewhere that, given the correct organic or policy-induced demand conditions, they continue to do so decade after decade. This became to be known as the "build to grow" approach to the grid expansion. This approach was problematic in the transition period from fast demand growth to slow or negative growth. It resulted in excess capacity that still had to be recovered through rates, resulting in higher prices. That is a risk that has to be weighed against the risk of insufficient capacity as a result of deregulation. It results in loss of reliability including rolling blackouts. Ultimately, in the assessment of approaches to facilitate generation growth to increase electrification while maintaining reliability, the safer bet is on an approach with an upward bias with "cushioning" rather than an approach with a downwards "just in time" bias.

Why would policy-makers risk relying on the deregulation approach that has not shown it can "do the job"?

Why Can't We Just Tweak Alberta's Energy-Only Market?

In the face of enormous political pressure resulting from the unprecedented retail price increases (and the need for government subsidies), excessive profits, and multiple EEA3 alerts in August 2023, the government asked AESO and MSA to provide it with recommendations to reform the energy-only market. In March 2024, the government directed AESO to implement the Restructured Energy Market (REM) that AESO recommended in January 2024.

Conceptually, the REM report consists of three sections. The first offers a high-level assessment of the pros and cons of four of the main high-level approaches to the generation segment; an energy-only market, a capacity market, long-term contracts (LTCs), and cost of service (COS) regulation. Based on an erroneous analysis, AESO recommends the energy-only market as "the best framework to ensure an affordable and reliable system for Albertans." Such an evidence-free assertion is shocking given the pricing and reliability situation that Albertans have lived through in the last three years and which has been documented in this report.

Having selected the current approach, AESO recognized that business as usual was not politically acceptable, and thus something needed to be done within the narrow parameters of the energy-only market model. So, the second and third sections of the REM report cover a series of AESO recommendations to be implemented in the near-term of six to 24 months, and in the medium-term of two to five years. We discuss some of the recommendations below, with the caveat that the details of many of the near-term and all of the medium-term plans will take months or more likely years to consult on, finalize, and implement.

> One important point to keep in mind is that these remain very modest tweaks when it comes to sector reform, especially considering that Alberta is only one of two jurisdictions in North America (the other being Texas) that maintains an energy-only market.

The other competitive ISOs started as, or evolved into, capacity markets or are a hybrid of LTCs and COS like IESO, the Ontario market.

AESO does not propose moving to a capacity market as the previous government initiated in 2016 and had cancelled in 2019 by the incoming government. Nor do they propose the increase of LTCs like the REP in 2017-18, also under the previous government. These crucial tweaks are provisions that have generally been implemented in other ISOs that have updated their markets since deregulation was first introduced approximately 20 to 25 years ago. In this regard, Alberta is simply catching up, not solving the underlying problem.

One of the proposed near-term measures is to establish a "market power" mitigation provision. Such types of measures are now standard in most other ISOs and are designed to regulate the ability of generators to earn excess profits in a given period. In this regard, it is a delayed recognition that market power exists in the Alberta market and some measures should be put in place to limit the negative effects of its exercise. Note that this is a different approach from trying to reduce market power directly by reducing market concentration. The proposed measures would establish a formula that would limit the prices offered to the pool by generators with market power, after they were deemed to have earned sufficient revenues during that month, to have made a reasonable contribution to their fixed costs.

If that sounds complicated and a lot like regulation, the very thing an unregulated electricity market intended to avoid, it's because it *is*. The parameters for design of such mitigation measures plainly have to be established administratively, not by the invisible hand of the market. Then there is the compliance and monitoring performed by, that's right, the government. And all this just to regulate *one component* of the generation cycle: the peaks, in effect to try to make sure beforehand that they are not *too* peaky, while ignoring the rest of the cycle.

Ultimately, such mitigation measures mean that profit-driven price-gouging will still be permitted, just not to the extent allowed during 2022 and 2023.

In the medium-term, and in addition to scarcity pricing mechanisms that would complement or replace the proposed near-term market power mitigation measures discussed above, the other proposed change is to introduce a day-ahead market. Most other ISOs already run day-ahead markets together with the real-time market. The day-ahead market is based on forecasted demand for the next day, while the remaining real-time transactions would balance actual supply and demand. The idea is that most of the transactions would take place in the day-ahead market rather than the real-time market.

Having described the energy-only market and its proposed 2.0 version, the REM, ***Table 3*** replicates and adds to the assessment framework in the REM report, providing a more detailed rationale for arguing that its assessment is erroneous. Table 3 includes two approaches that are under consideration: the energy-only market that currently holds in Alberta and its 2.0 version the REM, and the Cost of Service/Re-regulation that was included in the REM report and recommended in our work. The second and third approaches, assessed but not recommended by AESO (the capacity market and LTCs), are not included in Table 3. For each approach there is the original

AESO Assessment based on the graphic of ● for "objective likely met," ◐ for "objective possible but challenges" and ◔ for "objective unlikely met." AESO included four objectives: reliability, affordability, decarbonization, and implementation. Based on the research in this report, we add "price volatility" and "growth for electrification."

***Table 3**: Assessment of Energy-Only Versus Regulation*

Source: AESO (2024b), Author's research.

Assessment by	Energy-only Market/REM		Cost of Service/ Regulation		Comment
	AESO	Author	AESO	Author	
1. Reliability	◐	◔	●	●	No disagreement on "objective likely met" assessment for Regulation. In the face of the evidence presented in chapter 2, pp. 28-29, AESO's assessment that the energy-only market is "objective possible but challenges" is not credible. A more appropriate assessment is "objective unlikely met".
2. Affordability	●	◔	◔	●	AESO provides no evidence to support its assessment that the energy-only market is "objective likely met". In contrast, chapter 2, pp. 23-27, provides extensive evidence to support the alternative assessment of "objective unlikely met". Likewise, for the reasons set out in chapter 2 and chapter 3, pp. 31-32, the AESO assessment for Regulation is not appropriate and instead should be "objective likely met".
3. Price Volatility	N/A	◔	N/A	●	AESO did not directly address the intrinsic cyclicality of prices and investment in the energy-only market. As set out in chapter 2, pp. 26-28, price volatility is not only undesirable, but combined with retail competition, it is most likely to disadvantage low-income and other vulnerable households. That is why the energy-only market is assessed "objective unlikely met" and Regulation as "objective likely met".
4. Decarbonization	◐	◐	●	●	No disagreement on "objective likely met" assessment for Regulation and "objective possible but challenges" for the energy-only market.
5. Growth for Electrification	N/A	◐	N/A	●	AESO did not address the growth aspect of electrification. The energy-only market has not demonstrated the ability to facilitate the significant and decadal growth necessary for electrification, as set out in chapter 3, p. 40,. For this reason, it is assessed "objective possible but challenges". In contrast, the Regulation approach was designed for growth and therefore is assessed "objective likely met."
6. Implementation	●	●	◔	◐	No disagreement on "objective likely met" assessment for the energy-only market; the reforms are relatively modest and well understood. AESO assesses Regulation as "objective unlikely met," but, as argued in chapter 3, p. 32, a more accurate assessment is "objective possible but challenges" because while the reform would be more substantive, the final objective of Regulation is already practiced in other segments in Alberta (and was previously applied to the generation segment in Alberta) and no new institutions or processes would have to be established.

Implementation: No Leap of Faith Needed

Implementing re-regulation of the generation segment would be relatively straightforward, less complex, and faster than the process of deregulation was. De-regulation required multiple rounds of legislation, the creation of new institutions (such as AESO and the Market Surveillance Administrator) and costly, contentious and long-lasting transition mechanisms (such as PPAs).

For re-regulation, no new institutions would be required, some could be eliminated (such as the MSA), and the functions of others could be reduced considerably (as with AESO). The economic regulation of the generation segment would return to the Alberta Utility Commission (AUC), which already undertakes that function for the distribution and transmission segments.

Regulation of the generation segment could take different forms, tailored to best achieve the objectives of ensuring lower and stable prices, and increased reliability, all while maintaining the incentives for generation entities, both private and public, to invest in to increase generation capacity consistent with electrification goals.

It is likely that cost of service (COS) regulation would first be applied to most or all of the generation assets of the larger generation companies, for example those that have more than 5% of market share. As noted above, there are currently five such firms that combined make up about 54% of the Alberta market. Their portfolios mostly consist of well-understood technologies, such as gas, hydro, wind, and solar, that have been the subject of COS regulation in Canada and elsewhere.

The COS regulation could also be applied to smaller generation entities such as those associated with municipal entities, and, most critically to the newly-created Crown corporation, Alberta Power, that is further developed in the next chapter.

The COS regulation is a long standing and resilient form of regulation because through a series of public processes, it is designed to directly balance the relationship and interests between users and firms. Under COS regulation, the economic regulatory agency determines the revenues that the regulated firm is entitled to collect via its rates for the company to recover its costs and to earn a reasonable profit. The rate-setting is typically done every 3-5 years through a regulatory process called a rate case. During this phase, consumer groups and other interested parties may intervene to have their say on the merits of the proposals submitted by the firm. The COS regulation is appropriate for larger generation firms as they are more likely to be able to exert market power and hence, it is appropriate to regulate their profits via their rates. The COS regulation is the manner in which the AUC currently regulates the transmission segment in Alberta.

Incentive regulation refers to a series of approaches that complement or substitute for the COS regulation designed to include more features of competition while safeguarding reliability. There are different names for different flavours of incentive regulation, including performance-based regulation (PBR), multi-year rate plans or performance incentive mechanisms. Most commonly, PBR is implemented on a segment or an industry that was previously COS-regulated.

For example, the AUC had traditionally regulated the distribution segment in Alberta through a COS regulation, but recently transitioned to PBR. Once having established a reasonable revenue foundation based on the COS regulation, PBR can incentivise the firm to operate more efficiently during the term of the plan (typically five years). This is done by setting price caps or implementing other mechanisms to provide more flexibility to the firm. The objective is for the company to have greater incentives to be efficient and thus have increased profits related to COS regulation. Quality of service can be safeguarded through separate requirements. PBR also reduces the regulatory burden relative to the COS regulation. Once the formula is set, the firm does not get costs approved as frequently. At the end of the term, a traditional COS process could take place to "reset the rates" or a continuation of the pure incentive scheme could occur.

In this manner, PBR with an initial-cost-setting COS regulation component, could also be the first option to be applied to one or all of the large generation operators discussed above, including the newly-created Alberta Power. More generally, because of the relative advantage of its lower regulatory burden, a form of PBR could be the preferred option for smaller generation companies because these are less likely to be able to individually, or perhaps in combination, able to exert market power.

The last form of regulatory mechanism that could be considered are LTCs. Alberta already uses LTCs in the generation segment in the case of the Renewable Electricity Program (REP) auctions implemented in 2017. Most existing large generation entities already include LTC-like hedging and offtake agreement mechanisms to be able to stabilize their revenue streams. Similarly, many smaller operators, including stand-alone wind and solar projects, have offtake agreements with corporate firms.

Therefore, going forward, it is clear that the current LTCs would remain as a bilateral contract with AESO. Many of the smaller operators that have majority offtake agreements could also be re-contracted with AESO through an LTC mechanism.

This is not to downplay the time and effort required to transition back to a regulated generation segment. Unlike the highly disruptive and high-risk "leap of faith" that was the multi-year process of deregulation, a return to regulation is a low-risk transition to a well-known environment that already exists for the distribution and transmission segments of the sector and for some generation assets as well.

We know how to do this. Alberta already did it, and did it very well, for decades.

CHAPTER 4

Increasing Public Ownership

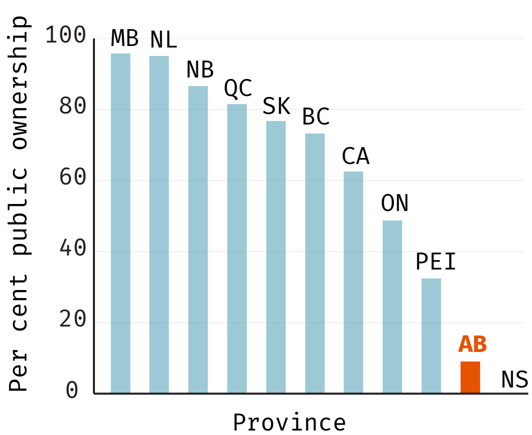
Increasing public ownership of Alberta's electricity sector through a new Crown corporation, Alberta Power, would enhance affordability, reliability, and democratic control while accelerating decarbonization efforts.

Private and Public Ownership

ALBERTA WOULD NOT be going alone here. In the electricity sector, the debate over the best way to run a grid has been firmly decided in most of the country in favour of public ownership through the establishment of a series of Crown corporations, as noted in Chapter 1.

Figure 29 highlights this. For the country as a whole, Crown corporations own a total of 63% of the installed capacity. Across the provinces, this varies

FIGURE 29: *PER CENT OF PUBLICLY-OWNED INSTALLED CAPACITY, BY PROVINCE (2022)*



Source: Statistics Canada (2024h), Author's calculations.

from a high of more than 90% in Manitoba and Newfoundland, to lows of 9% for Alberta and 0% for Nova Scotia (which was fully privatized in 1991).

Few Albertans are likely aware that if it were not for a tiny 0.06% difference in voting in the plebiscite of 1948, it is quite likely that a province-wide Crown corporation would have been assembled over the subsequent years in Alberta too, along the lines of the other Western provinces, of Saskatchewan, Manitoba, and BC.

Once they were established in their modern form by the 1960s, most of the provincial Crown corporations survived the political economy turn to privatization of the 1990s. A very practical reason for this longevity is that the model just works.

First, it works because Crown corporations can borrow at a much lower interest rate than an equivalent private company could, even a regulated private utility. These lower financing costs are very important in a highly capital-intensive sector such as electricity, where borrowing for large, meaty chunks of infrastructure (such as transmission lines or new generating plants) can be high and therefore the cost of borrowing is critical.

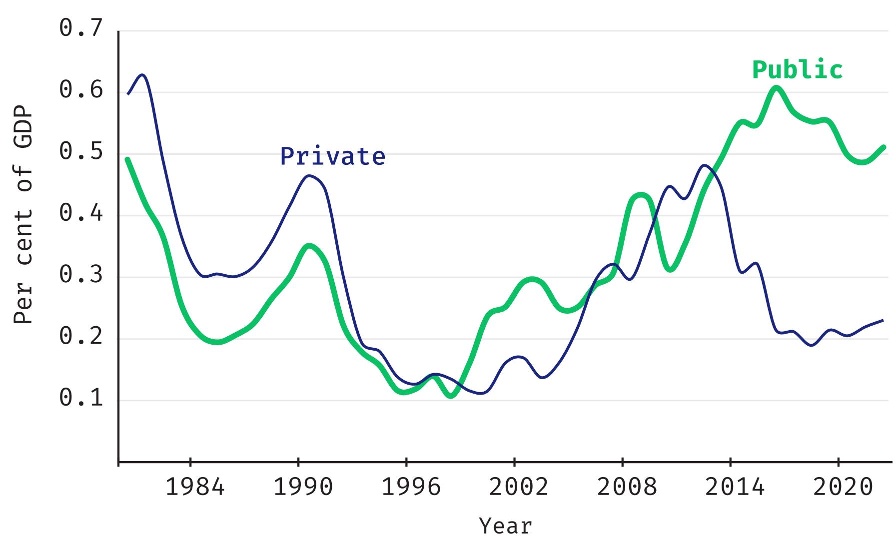
Secondly, Crown corporations work because they can and do take a long-term, often generational perspective on investments that have long lead times and extended pay-back periods (such as large hydro-electric projects with 80 to 100-year lifetimes). Private project financing for deregulated markets simply does not exist much beyond a dozen years. Therefore, the private sector will not undertake such projects, not because they are not profitable, but because of imperfect credit markets or shareholder pressure over quarterly earnings. This means that deregulation markets are likely to have a sub-optimal generation portfolio relative to one where such credit restrictions were not to exist. Sub-optimal here refers to sectorwide long-term system costs. We would expect to see a relatively larger share of relatively quicker payback assets that can be project financed, such as gas generation, and a relatively smaller share of slower payback assets that cannot, such as hydro and nuclear.

Thirdly, Crown corporations work because any profits can be returned to the public in the form of dividends to the sole shareholder (the province), rather than to shareholders. Depending on what voters prefer, the province can either increase spending or return it to residents in the form of lower taxes. One variation of this is the “Power at Cost” mandate wherein profits above a reasonable level are not permitted by the objects of the Crown corporation.

Figure 30 shows how public and private investment in the electricity sector is similar but also varies over time. Both types of investment decreased in the 1980s and 1990s, as expectations of decreasing electricity growth took hold. It was not until the early 2000s that private and public investment picked up. However, there is a large divergence in investment that starts in the early 2010s that by the late 2010s has become a chasm, wherein the public sector investment is more than double that of the private sector over the 2015-2023 period.

The highly privatized generation segment in Alberta, as one of two outliers in Canada, contrasts with the still-regulated distribution segment, in which Alberta is in the middle of the pack.

***Figure 30**: Public and Private Electricity Investment, Canada*



Source: Statistics Canada (2024a), Author’s calculations.

***Table 4**: Distribution Segment in Alberta and Rest of Canada, by Subscribers*
Source: Author's research and calculations (2024).

		Alberta		Rest of Canada	
Segment	**Sub-group**	**Breakdown**	**Sum**	**Breakdown**	**Sum**
Public	Provincial	0%	60%	59%	87%
	Municipal	58%		28%	
	Co-op	2%		0.1%	
Private		40%	40%	13%	13%
Total		*100%*	*100%*	*100%*	*100%*

Table 4 shows that based on the number of customers, Alberta's municipal utilities make up about 58% of the market. Add to that the 35,000 customers of Alberta's unique REAs, and Alberta's public ownership climbs to about 60%. This compares to about 87% in the rest of Canada.

Table 4 confirms that the private/public balance discussed in Chapter 1 has been maintained in the distribution segment, but not in the generation segment. This loss of balance has had a negative impact on performance.

Historically, the political-economy tension between private and public enterprise in Alberta kept the two in check. If private enterprise was not sufficiently aligned with what the public considered to be its interest, the political backlash (in a call for more regulation or a transfer to public ownership through municipalization, as in the case of Edmonton, Calgary, and others, or through provincialization, as in the case of the 1948 plebiscite). This kept private enterprise in check. Those checks and balances have effectively been eliminated in the generation segment in Alberta, and its residents are worse off for it.

Why Public Power Matters

We have covered how deregulation has been a disaster and set out an instrumental rationale for the return of controlling profits in the generation segment and an increase in public ownership to move towards what exists in many other provinces. We argued that a revival of government intervention and public ownership in this sector is the best way to achieve lower electricity costs, a return to a reliable grid, faster decarbonization, and many other important economic and social goals.

But beyond these instrumental reasons, there is also democratic principle at stake.

When private electric companies decide what they are going to charge customers, how much they will spend to maintain critical infrastructure, and whether to provide a service to a community, the decision is only made in service of maximization of profit. It can be no other way. For a company to survive, profit must be their only goal.

This means that if maintaining a reliable grid that keeps Albertans safe amidst bleak midwinter temperatures of -50°C is not profitable, then that grid will not be reliably maintained.

In the 1940s, when the private franchise monopolies in Alberta refused to service rural communities fast enough, it was for the same reason: there was no money in it. That was what the 1948 Public Ownership Plebiscite in Alberta was all about.

Yet when a public service is in charge of the grid, it has a very different goal: serving the people of Alberta. Canada is a democracy, not a dictatorship. That means that when the government does something in the electricity sector, the government isn't a *them*; it's an us. If we establish a new electricity Crown corporation in Alberta and bring back regulation to the sector, then that isn't somebody else doing all of that. It would be the democratic majority, us, deciding amongst ourselves that this is what we want.

That's what the title of this report is all about. Maximizing shareholder value should not be what governs our electric grid; we should govern it ourselves. Public power means that we once again become masters of our own home.

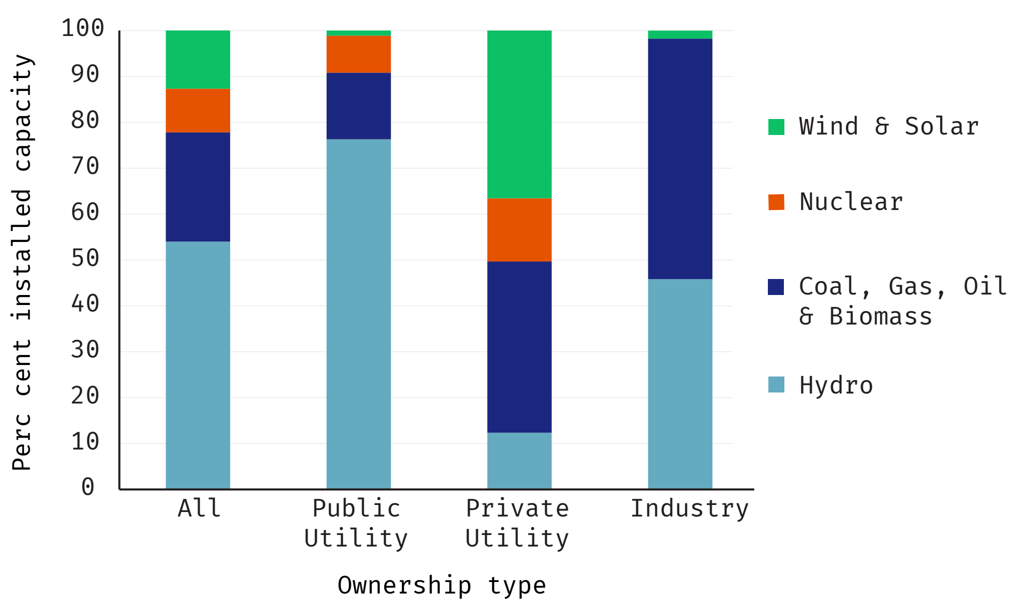
Industrial Policy: The Americans Are Already Doing It

The electricity sector has long been considered fundamental to economic development and nation-building. As such, along with other strategic sectors, this has historically been the subject of active industrial policy, including through public ownership.

Under the Biden Administration, the United States took a major swerve back into industrial policy for climate, energy sovereignty, and national security reasons. If Washington is no longer afraid of the role of government to make capitalism work better than it can do on its own, why should Albertans be worried? Industrial policy can take many forms, two of which we explore below.

Figure 31 shows the relationship between ownership and generation technologies. On average, publicly-owned generation in Canada has had lower emissions than private generation. Figure 31 shows that by capacity, in 2022 public generation had 82% zero-emissions generation (hydro, nuclear, wind and solar), while private generation had 65%.[20]

Figure 31: *Installed Capacity by Ownership Type, Canada (2022)*



Source: Statistics Canada (2024h), Author's calculations.

A more activist example of the different industrial policy options available through private versus public generation is the coal phaseout in Ontario and Alberta. In Ontario, there was political consensus to phase out coal in the early 2000s. All coal generation, which at the time accounted for about 25% of generation, was produced by the OPG, a Crown corporation. Therefore, the phaseout involved the province, as the sole shareholder, simply directing OPG to shutter its coal generation units in a planned manner, while also directing nuclear generation to ramp up to replace most of the lost output. From the beginning of the implementation to completion, the total duration was seven to eight years. This was often described as the single largest act of decarbonization in North American history.

Alberta's situation is different. In Alberta, the coal generation assets are not owned by the province. After the political decision to speed up the federally-mandated phase out of coal, the provincial government had to *negotiate* the timing and compensation associated with shutting them down, rather than just telling managers to "make it so." Compensation amounted to the hundreds of millions of dollars. The timing of the shut down was also not subject to the agreement and not coordinated to ensure reliability.

As noted in Chapter 1, the REP of 2017-2018 was a form of industrial policy. It reflected an economical, political decision that the roll-out of renewables, at that point, could not be left to the market and hence, the amount of generation would be procured centrally.

There are softer, perhaps more strategic aspects of industrial policy, associated with energy security and sovereignty. Until very recently, these latter issues had not been prominent since the 1970s energy crises. But since the 2022-2023 global crisis prompted by Russia's invasion of Ukraine and Germany's decision to shutter its nuclear power plants, the question of energy security has found renewed significance. The subject manifests itself in a number of ways. Ultimately, it is associated with electricity independence, which is serviced by a government being able to direct a Crown corporation to have "enough in the tank" to provide for oneself in times of crises, and not have to depend on others.

A related aspect is sovereignty. This is highlighted by the resolution tabled by the current government in November 2023, that for the first time invoked the *Alberta Sovereignty Within a United Canada Act* (ASA). The resolution identifies the Clean Electricity Regulations proposed by the federal government as the "Federal Initiative" that will cause, or is anticipated to cause, harm through reduced investment and reliability and increasing prices.

The resolution calls for the government of Alberta and any provincial entity to refrain from enforcing or implementing the Clean Electricity Regulations. However, as with coal phaseout, Alberta does not have the necessary levers—provincial ownership—to be able to implement its objectives under the ASA. So, as set out in ***Figure 32***, the resolution necessarily goes further, by calling for a study to explore the potential establishment of a provincial Crown corporation.

Figure 32: *Except from ASA Resolution, 2023*

> (c) in consultation and collaboration with the Alberta Electric System Operator, the Alberta Utilities Commission, the Market Surveillance Administrator, consumers, industry, Indigenous communities, and other relevant stakeholders, explore the feasibility and effectiveness of the potential establishment of a provincial Crown corporation for the purpose of achieving and securing the Provincial Electrical System Objectives.

Source: Legislative Assembly of Alberta (2023)

Public Generation and Unions

Our report has focused on economic regulation and public ownership first, and on labour and union matters second. We have not focussed on any of the other important issues associated with the electricity sector generally, or other related matters such as climate, except as they relate to our priority matters.

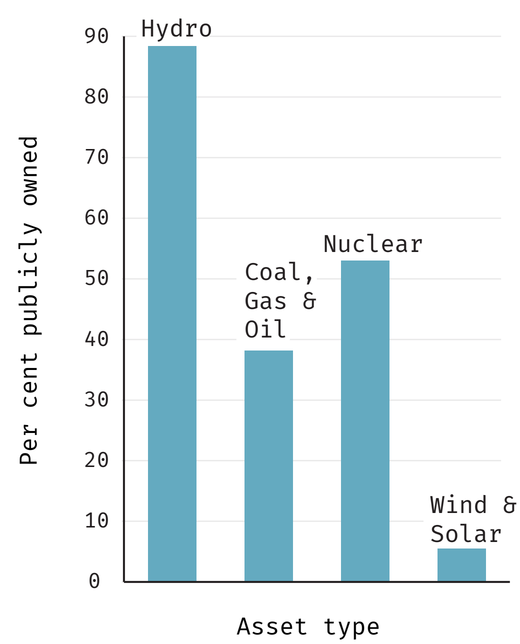
It is in this context that we discuss specific generation technologies, public ownership, and union labour. ***Figure 33*** presents ownership data from a technology perspective. As previously described, it shows that hydroelectricity in Canada is almost 90% owned by Crown corporations. This is not surprising, given the weight of BC Hydro, Manitoba Hydro, Hydro-Quebec and Newfoundland Hydro in the Canadian electricity sectors.[21]

A similar argument applies to nuclear power in Canada. It was 100% publicly-built, likely reflecting the very large up-front investments required for long lived assets with long payback periods. What stands out in Figure 33, however, is the ownership status of wind and solar, which is only at a 6% rate of public ownership.[22] This relatively tiny proportion of public ownership is not unique to Canada. This is also seen in the USA and much of Europe. There are two related reasons for this.

One is that wind and solar have been mostly developed in the last 10 to 20 years. That is well past the inflection point of the early 1990s neoliberal political economy that we pointed out in Chapter 1 when Canada and many industrialized countries began to favour private ownership for existing and new generation assets. In this context, it was the political economy choice that wind and solar *should* be developed by the private sector, both within deregulated provinces and those with Crown corporations. The latter were generally implemented by provincial policy to provide a form of an "escape valve" for private capital participation in the electricity sector. It was in the form of independent power producers (IPPs) without having to unbundle or privatize the Crown corporation. The Crown corporation was required to connect the IPP to the transmission network and contract with them, generally based on LTCs. For example, IPPs make up non-trivial proportions of the installed capacity in BC, Saskatchewan, and Quebec.

Another reason for private sector preference for wind and solar is that it has relatively low labour operating inputs, and those labour inputs tend to be *non-union*.

***Figure 33**: Per Cent of Public Ownership of Generation Technology, Canada (2022)*



Source: Statistics Canada (2024h), Author's calculations.

Figure 34 shows that wind and solar have the lowest rate of union labour of any generation technology: 13%.[23]

These relatively low union rates for wind and solar in turn reflect a number of factors. These include technologies that have been rolled out during a time of low union density rates by mostly new corporate entities, namely IPPs, that have no history of union membership. Further and perhaps even more importantly, organization of a low number of geographically dispersed solar and wind employees is a practical challenge for unions compared to traditional hydro, nuclear, or gas plants that concentrate many more workers at single sites that are closer to urban centres.

Wind and solar do not have to be privately-owned and non-union. For example, the Crown corporation PEI Energy, owns half of the island's wind capacity. But the most significant recent development in this regard is the announcement of Hydro-Québec's change in policy on public ownership. Quebec had originally outsourced its wind generation to IPPs. But according to its later assessment, this approach led to a lack of coordination, higher costs and local opposition. As a result, the new policy is to leverage Hydro-Québec's strengths as a Crown corporation to plan, build and operate large-scale wind projects; a strategy that the utility expects will save 20% over smaller IPP-operated procured projects. On a case-by-case basis, Hydro-Québec will co-own some of the projects with municipalities or Indigenous communities. Even there, IPPs will still continue to be encouraged to develop some smaller-scale wind projects, as required.

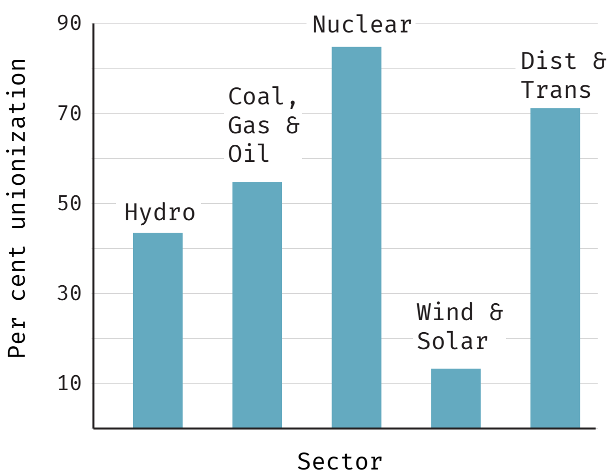


FIGURE 34*: PER CENT OF UNION LABOUR BY MAIN ELECTRICITY INDUSTRY CODE, CANADA (2012-17)*

Source: Statistics Canada (2020), Author's calculations.

Note: Labour is 100% allocated based on primary enterprise-level North American Industry Classification System code; many enterprises are vertically-integrated and hence could be coded either under distribution or transmission of the main generation technology.

How Do We Do This?

There are many possible routes to increased public ownership in the Alberta electricity sector. As summarized in Chapter 1, the experience of the establishment and growth of publicly-owned utilities, whether at the municipal or provincial level, in Alberta or other provinces, is one of a decades-long process that combines organic growth and the acquisition of the privately-owned companies based on the principle of promoting local and provincial democracy.

> This report adopts a long view of increased public ownership in Alberta through democratic means.

The first step in this process is the creation of the legal, institutional, and financial framework to allow for this process to begin and be maintained going forward. Our preferred approach would require only one new institution to be established.

This new institution would be a provincially-owned Crown corporation, which we will refer to as Alberta Power. Alberta Power could own and operate distribution, transmission, and generation assets and would be subject to regulation by the AUC. Like other Alberta Crown corporations and electricity Crown corporations in other provinces, Alberta Power would require establishing legislation that would set out its governance structure (board of directors), mandate, and corporate structure.

Alberta has a long history of, and experience with, provincial corporations. For instance, very early on Alberta bought out the assets of Bell Canada in the province in 1908 for $675,000 and built out the telecommunications network through what would become the provincial Crown corporation Alberta Government Telephones, which was privatized in 1990. To this day, ATB Financial (established as Alberta Treasury Branches in 1938) is a unique only-in-Alberta Crown corporation providing banking and other financial services. It is the largest Alberta-based financial institution, with assets of $62 billion, 820,000 clients and 267 branches and agencies.[24] The Alberta government not only recently mused about the creation of an electricity Crown corporation, as noted above, but also continues to create new Crown corporations in other sectors. Most recently, the government announced the creation of the Canadian Centre of Recovery Excellence.[25] Alberta Power would be classified in the same manner as ATB Financial (and BC Hydro, SaskPower, etc.), as what is referred to as a "government business enterprise" Crown corporation.

While some of the larger electricity Crown corporations have the authority to issue long-term debt on their own, most are structured, so they borrow from the province, either directly or through umbrella holding Crown companies, such as the Crown Investments Corporation of Saskatchewan.

To begin the process, and at least in the medium-term, it is likely that Alberta Power would borrow directly from the province. As a government business enterprise, that borrowing would be to purchase revenue-generating assets. Alberta Power would also have a support function that would provide advisory services to the municipalities that are interested in creating or increasing the size of their municipally-owned utilities.

This brings us to the second institution needed, one that would provide financing for municipalities to create or grow their own utilities. This institution would be a separate institution from Alberta Power. There are a number of models from the US, Canada, and Alberta for such an institution, but the best likely candidate already exists and therefore would not have to be created from scratch.

In terms of other models, for example, the Rural Electrification Administration of the USA, was set up in the 1930s to provide federal loans for the installation of electrical distribution systems channeled through electric power co-operatives. This was the model that was introduced in Alberta in the 1940s, that allowed rural co-ops to finance the construction of the distribution networks in rural Alberta. The *Rural Electrification Loan Act* is still in force in Alberta to this day and allows for 10-year loans of up to $75 million to establish rural electrification associations (REAs) to promote rural electrification.

Alberta has traditionally had two large lending Crown corporations for specific clients. The Agriculture Financial Service Corporation is designed to provided insurance and lending services to farmers with a current portfolio of loans of over $2 billion. Most interestingly for our purposes, until 2020, Alberta also had a separate Crown corporation, the Alberta Capital Finance Authority that offered Alberta municipalities low-cost loans for up to 40 years. The government dissolved the authority and brought over its portfolio of $16 billion in outstanding loans and future lending facility directly to the Government of Alberta under its Loans to Local Authorities program.[26] While it would no longer provide "low-cost loans," the program provides eligible municipalities with more "financing of capital projects" including for equipment, land, buildings, and electric infrastructure.

Taking all this into account, the existing Loans to Local Authorities program is likely the best institution through which municipalities that are interested in creating or increasing the size of their municipally-owned utilities could access financing. It may need to be revised to potentially accommodate this new enhanced function.

Taking this institutional framework into practice, and keeping in mind the decades-long process that combines organic growth, and the acquisition of the privately-owned companies based on the principle of promoting local and provincial democracy, how could this work in practice?

It will depend on whether the segment is distribution, transmission, or generation and whether it is brownfield or greenfield situations.

Let us start with a distribution brownfield example of a municipality being served by either ATCO or FortisAlberta. If the residents of the municipality were to express their desire to be served by a publicly-owned distribution company, they would have two choices. One would be to establish their own municipally-owned utility by purchasing the assets from either ATCO or FortisAlberta. The municipality could seek advice from Alberta Power as to its options in this regard.

The municipality has a series of options. One is to own the assets (including through a loan from the Loans to Local Authorities program) and operate the utility such as Edmonton or Red Deer. It could just own the assets and allow Alberta Power to operate the municipal utility. This type of arrangement is already well established in Alberta wherein some of the larger LTCs operate the distribution assets of networks still owned by REAs. Lastly, the municipality could request that Alberta Power purchase the distribution assets (based on its own borrowing) and operate the utility.

Brownfield transmission and generation would work in a similar manner. The residents of a municipality with an established or newly-created municipal distribution utility could decide to acquire the transmission and/or generation assets that provide them with those services. As in the example above, there would be a number of options with respect to purchasing/operating the assets, including whether the municipality wanted to finance/operate themselves or have Alberta Power do so.

More generally, including for brownfield transmission and generation facilities that are distant from existing or interested municipalities, or which the private owners were no longer interested in owning and operating, Alberta Power could on its own acquire and operate that infrastructure. A case in point is the generation assets currently owned by Heartland, which is currently the third largest generation entity in Alberta. These assets were originally owned by ATCO, which in 2019 sold them to a private equity firm, Energy Capital Partners, which is now selling them to TransAlta.

At either of those two points, Alberta Power could have purchased all or some of those assets, had it existed at the time. The transaction price of the current transaction, $658 million, is relatively modest at $357 per kilowatt of capacity, which as TransAlta notes is "well below replacement cost of current and other forms of reliable generation, providing a low-cost expansion of our ability to deliver reliable generation to the market demands of Alberta."[27] That price tag, that provides for multi-decade revenue-generating infrastructure, is certainly lower than the $1 billion that the Government of Alberta expended to subsidize retail electricity prices for under a year. This is all to say that there will be other opportunities for Alberta Power to purchase existing transmission and/or generation assets in Alberta.

The greenfield situation refers to new and incremental transmission or generation facilities that are required for the expansion and growth of the grid to promote electrification objectives. As noted, these could be up to double of the current generation segment by 2050 and have continued growth beyond. This type of organic growth was one of the major avenues through which Crown corporations in other provinces expanded in the past. In this instance, Alberta Power would compete indirectly with the private sector to be the builder, owner, and operator of those needed transmission or generation assets.

Alberta Power. It has a nice ring to it, no?

Conclusion

The Alberta electricity sector deregulation experiment of 2001 has been an **abject failure**.

Promises of lower prices and increased reliability have not been fulfilled. Nor will they be achieved by the modest reforms proposed in the Restructured Energy Market expected to be implemented over the next five years. The Restructured Energy Market will not save Alberta from higher prices, price volatility, stagnant employment in the electricity sector and profiteering, because it does not get at the root of the problem. Alberta is by far the smallest, and likely the most concentrated market in North America. These are foundational weaknesses that limit the benefits of any market design compared to re-regulation.

The process of re-regulation would be straightforward and could be completed in the same time frame as the REM. Unlike the deregulation experiment, it would not require the creation of new institutions and complex arrangements. Nor would it require the detailed design of the Restructured Energy Market, which is not expected to be finalized until sometime in 2025. Economic regulation already exists in the distribution and transmission segments in Alberta, administered by a well-respected economic regulator, the Alberta Utilities Commission. The generation segment had been previously regulated in Alberta and had performed very well. It is clear now that the move to restructure the sector was no more than an ideological leap of faith.

Alberta's municipally-owned utilities continue to serve most residents and businesses in the province, thus maintaining an important private/public balance in the distribution segment. The tension between private and public enterprise in Alberta historically kept each other in check. If private enterprise was not sufficiently aligned with what the public considered to be in its interest, the political backlash (in the form of a call for more regulation or for a transfer to public ownership) kept private enterprise democratically domesticated. Those checks and balances have effectively been eliminated in the generation segment in Alberta and its residents are worse off because of it.

To promote the public interest, it is time to end the disastrous deregulation experiment and to return to a healthier public-private balance in Alberta by establishing a new provincially-owned Crown corporation.

Cheaper, cleaner, safer, less volatile, more responsive, and more democratic, with stronger unions and thus a stronger middle class. **That's the real Alberta advantage that we need.**

Endnotes

1. (from page 20) In the electricity sector, there are a number of terms used to describe a long-term arrangement to purchase or sell electricity. These include the terms Power Purchase Agreement (PPA), Offtake Agreement, etc. However, in Alberta, the acronym "PPA" is associated with the Power Purchase Arrangements, as described above. For the avoidance of doubt, therefore, in this report, PPA(s) will refer to these Alberta-specific Power Purchase Arrangements. We refer to contracting arrangements wherein a generation entity sells to a network operator (e.g., AESO in Alberta, Independent Electricity System Operator (IESO) in Ontario, etc.) or a public or private utility (e.g., BC Hydro, SaskPower, etc.) as LTCs. We refer to contracting arrangements wherein a generation entity sells to a corporate party (such as Amazon for a Data Centre, etc.) that is not a network operator or a utility as an Offtake Agreement.

2. (from page 21) See for instance Kwoka et al (2010) and Arocena et al (2012).

3. (from page 23) Prices for both sources of data discussed below are "all in" and included charges for distribution, transmission and generation (energy) services. Further, both sources also make available data for industrial users of different sizes.

4. (from page 23) Based on a compilation of data collected by Hydro-Québec from 1998 to 2023 for normalized per kWh prices for 12 cities: Montréal, Calgary, Charlottetown, Edmonton, Halifax, Moncton, Ottawa, Regina, St. John's, Toronto, Vancouver, and Winnipeg. Hydro-Québec data captures price levels at a single point in time, generally April 1st of each year. Data for April 1, 2024, were not yet available when this report was finalized.

5. (from page 23) Based on data collected by Statistics Canada using the residential electricity component of the Consumer Price Index (CPI). The Statistics Canada index data captures price changes and presented on a quarterly basis as an intermediate point between annual and monthly observations. Quarterly data are calculated by averaging the corresponding three monthly observations, with the exception of 3Q2024 which only includes July and August, the last months available when this report was finalized.

6. (from page 24) System costs are calculated by multiplying quantities by prices for each year and each type of user. For quantities we identify five "representative customers" for each of the five types of users: "Residential", "Industrial (Dx)", "Commercial" and "Farm" (Agricultural) for distribution-connected users, and Industrial (Tx) for transmission-connected users. Data for 1998-2023 for users and usage are available in AUC (2024a). We set 2024 numbers to be the same as 2023. Residential, Industrial (Dx and Tx), Commercial and Farm electricity use averaged 15%, 59%, 23% and 3% over the 2001-24 period. For prices we use Hydro-Quebec (2023 and previous) reports with prices applicable for Edmonton as a proxy for Alberta. For each of the five representative customers we apply the average monthly bills from the closest match of class of consumer. For example, the 1998-2023 average residential usage in Alberta was 573 kWh/month, and so we use 625 kWh class of residential consumer from Hydro Quebec reports. We adjust these monthly bills for actual usage and multiply by the number of users to calculate Residential system costs. We do the same for the other four types of representative customers and aggregate to sector system costs. To take into account that during the 2020-24 period of increasing and volatile prices,

the Hydro-Quebec “listed” prices would be higher than effective prices resulting from industrial/commercial hedging and residential contracts in Alberta, we adjust downward listed prices based on percentage changes calculations presented in Figure 15, including a 25% annual reduction for 2024 relative to 2023. For a top-down reconciliation of Alberta system costs with Alberta prices, we apply a proportionate adjustment to all years so that the 2018 estimate is the same as the Alberta system costs estimate of $7.8 billion from Bishop et al (2020). After this reconciliation process there is a 0.0% difference with Bishop et al (2020) for the year 2018 and only a 2.5% difference for 2014.

7. (from page 24) Average Rest of Canada prices are calculated based on Hydro-Quebec (2023 and previous) reports, with prices applicable for Montréal, Charlottetown, Halifax, Moncton, Regina, St. John’s, Toronto, Vancouver, and Winnipeg used as proxies for their respective provinces. Because price data is not yet available for 2024, we use a 2% increase across all customer classes relative to 2023 based on estimates and projections in Figure 12. To take into account multi-billion dollar Government subsidies applied to retail prices in Ontario described in Sepulveda (2024), we adjust all Toronto prices upwards for the 2017-2023 period based on unit system cost percentage changes in MSP (2024). We calculate average weighted price for each representative customers by applying the respective provincial electricity usage for the Residential, Industrial, Commercial and Agricultural categories from Statistics Canada (2024j) as weights. This data is available 2005-22; we apply the 2005 weights for the 1998-2004 period and the 2022 weights for the 2023-24 period.

8. (from page 25) We use annual average CPI estimates from Statistics Canada (2024k), including a projected increase of 2.0% for 2024.

9. (from page 26) Most recently the government has announced that it will change the name of this default option starting in 2025 to the “Rate of Last Resort” and make other changes.

10. (from page 26) The monthly RRO prices and province-wide RRO and contract subscribers are available from AUC (2024c). This was calculated as the average contract price based on the largest retailer in Alberta, ENMAX, which in their quarterly financials. ENMAX (2024) reports their revenues for their contract and RRO for residential services. The MSA (2024) reports the number of contract subscribers by retailer, based on which calculations were made for average quarterly contract price. Using that as a proxy for all of Alberta, and with the published RRO, an Alberta-wide “RRO+contract” average price was constructed.

11. (from page 27) See Esplin (2022) and Jahn-Lang (2024).

12. (from page 32) These can be significant, for example with researchers having estimated initial set-up costs (operational, administrative, etc.) of $1 billion for Ontario over the 1999-2001 period, equivalent $1.7 billion in 2024 dollars. No equivalent estimates exist for the setup or ongoing costs of the deregulated system in Alberta.

13. (from page 33) These are the institutions, like AESO in Alberta, which administer the transmission and under which the mandated competitive wholesale market operates. Other Regional Transmission Organizations/ISOs operate under mostly voluntary exchange, similar to what occurs between Alberta and BC, for instance.

14. (from page 34) We will not repeat here the legal saga of the PPAs, including how they were voluntarily returned before expiring to the Balancing Pool for it to administer, and how a combination of lower wholesale rates and increased carbon levies, and the infamous “Enron clause” flipped the Consumer Allocations from a

rebate to a charge that Alberta consumers are still paying through a bill rider. Rather, our focus is more fundamental: the inability of the Alberta market to attract sufficient new entry so that when the PPAs ended, the exertion of market power in the newly re-concentrated market would have radically eased.

15. (from page 35) These are from Mackay and Mercadal (2024), that compared the experience of companies in deregulated states relative to a "control group" in states that did not deregulate. These results are consistent with the previous literature on efficiency and price comparisons, with the innovation related to the exertion of market power.

16. (from page 35) See Brown et al (2023).

17. (from page 36) The MSA has to use a hypothetical operator as a proxy because operator profits are not regulated in the Alberta market. Hence there is no regulatory requirement for operators to present approved regulatory accounting that would show such profits to the MSA, the AESO, or the AUC.

18. (from page 37) The MSA also undertook the same analysis for other types of generation assets, including, for natural gas peaker (plants that only run when there is high demand), wind, and solar. The average WACC for hypothetical gas peaker operators was higher than "Very High," at 17.4%. A hypothetical wind operator averaged a close-to-normal 8.1% WACC, while solar was moderately higher at 9.5%.

19. (from page 37) The other three larger generation entities with market shares greater than 5% (ENMAX, Suncor, and Heartland) do not report adjusted EBITDA on a segmented (generation-only, Alberta-only) basis. Such data is available on a quarterly basis from Capital Power from 1Q2019 and previously; however, such data is only available on a quarterly basis from TransAlta from 1Q2021 onwards.

20. (from page 48) This is not a causal argument but an observation; it is possible that there was a two-way relation, whereby provinces with large hydro resources, which require very large up-front investments with long-lived assets with long pay-back periods, found that the best way to structure their industry was via a Crown corporation.

21. (from page 50) As argued above, provinces with large hydro resources have found that the best way to structure their industry was through a Crown corporation. While this demonstrates a very strong relationship, it is not causal, as the hydro resources in Alberta are privately owned, for example.

22. (from page 50) Nuclear now shows a 50% rate of public ownership, due to a transfer of operational control to the private sector under the public-private partnership of Bruce Power.

23. (from page 51) While these results should be treated with some caution because of the limitations of this one-off study, they are consistent with the US Department of Energy (2024) analysis, in which wind and solar once again experience the lowest union rates, 11%.

24. (from page 52) See https://www.atb.com/company/about-atb/

25. (from page 52) See https://nationalpost.com/news/canada/core-albertas-new-addictions-crown-corporation

26. (from page 53) See https://www.alberta.ca/loans-to-local-authorities

27. (from page 54) See https://transalta.com/newsroom/transalta-to-acquire-heartland-generation-from-energy-capital-partners-for-658-million/

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About the Alberta Federation of Labour

The Alberta Federation of Labour is the leading voice for working Albertans, representing 26 affiliated trade unions and over 170,000 unionized workers across Alberta.

In 1912, unionized miners and tradespeople from southern Alberta first agreed to work together under the umbrella of a labour central. Since then, as the largest workers' organization in the province, the AFL fights to defend and advance the rights of working people, and we mobilize Albertans to affect change through collective action. We believe in the power of working together to achieve a better deal for workers and families.

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