POWER PLAY

TECHNICAL REPORT

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Introduction

This Technical Report accompanies the Canadian Climate Institute's *Power Play: How to supercharge Canada's clean electricity advantage* report, detailing the methodology and data sources that underlie the benchmark analysis and figures.

Power Play examines how Canadian provinces can expand clean electricity generation quickly and reliably while maintaining competitive rates for industrial users. The analysis benchmarks four Canadian provinces—Ontario (ON), Alberta (AB), Quebec (QC), and British Columbia (B.C.)—against six international jurisdictions and compares across six metrics. The international comparators were Germany (GER), the United Kingdom (U.K.), Norway (NO), New South Wales (NSW), Washington (WA), and Texas (TX). Together, these six metrics assess a jurisdiction's preparedness to attract investment in wind, solar, and battery projects that supply electricity, as well as the industrial projects that demand it:

- Metric 1: **Energy planning**
- Metric 2: **Planning for flexibility**
- Metric 3: **Transmission planning**
- Metric 4: **Electricity procurement**
- Metric 5: **Industrial rate modernization**
- Metric 6: **Climate policy certainty**

The metrics were selected based on expert interviews (see Power Play: Appendix A) as well as a review of the latest research. Each metric had to reflect conditions that policy can shape, demonstrate real impact on realizing a competitive electricity supply, show variation across the jurisdictions in this study and have available reliable data.

A few methodological notes apply across all metrics. First, our definition of the six metrics was often constrained by limited data availability. Moreover, multiple metrics look at historical data to draw conclusions about the future. Finally, the six selected metrics have relevance across all jurisdictions but their importance for specific markets differs.

Based on this benchmark analysis, Power Play identifies how Canadian governments can deliver low-cost power and enhance competitiveness for international capital. The study's findings and policy recommendations are documented in one federal report and two forthcoming provincial publications.

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Context-setting analysis

Industrial retail electricity rates

This figure shows the relative competitiveness of Canadian provincial electricity rates against international peers. For each of the 10 jurisdictions, we collected data on retail electricity rates for industrial consumers over the past five years. To maximize comparability of industrial rate data from different jurisdictions, we considered the following data characteristics and aligned them where feasible:

- How industrial customer classes are defined
- Which charges are included in retail electricity rates (e.g., energy charges, demand charges, consumer service charges, environmental surcharges, etc.)
- Whether average prices are reported on an annual basis
- Whether rates are reported in real (inflation-adjusted) or nominal (unadjusted) terms

Where necessary, we converted prices from local currency into Canadian dollars and standardized them to a common unit of energy (i.e.,¢/kWh).

Table 1 contains information on data sources and characteristics across the ten jurisdictions. Rates are reported in nominal terms, unless otherwise stated.

TABLE 1:

DATA SOURCES FOR HISTORICAL INDUSTRIAL ELECTRICITY RATES

Jurisdiction(s)	Source	Notes
AB, B.C., ON, QC	Hydro-Quebec	Industrial customer class: monthly consumption of at least 3,060,000 kWh and a power demand of 5,000 kW. Annual average rates exclude taxes, but include supply, transmission and distribution charges. As Hydro-Quebec publishes rates at the city-level we used the following cities as provincial representatives: **Alberta:** Edmonton Alberta operates a deregulated electricity market where industrial rates are subject to negotiation. Rates may vary by location. **B.C.:** Vancouver BC Hydro serves most of the province at uniform rates. Vancouver is largely representative of B.C. industrial customers. **Ontario:** Toronto Electricity rates are broadly consistent province-wide, though delivery charges can vary by local distributors. **Quebec:** Montreal Hydro-Quebec serves most of the province at uniform rates. Montreal is largely representative of Quebec industrial customers.
TX and WA	Berkeley Energy Markets and Planning	Industrial electricity rate data for US jurisdictions was sourced from EIA-861, an annual survey conducted by US Energy Information Administration, which collects data from electric utilities, power marketers, and system operators. EIA-861 does not prescribe a uniform definition of "industrial" customers, so definitions vary by utility. The industrial sector is broadly defined to include manufacturing, construction, mining, agriculture (irrigation), fishing, and forestry businesses. Annual average rates include volumetric, demand, and fixed customer charges.
U.K.	BEIS	Rates for large industrial users with annual consumption of 20,000–69,999 MWh, covering approximately 60 per cent of total industrial electricity sales. Average annual rates are inclusive of all taxes, including the Climate Change Levy.
GER and NO	Eurostat	Rates for large industrial consumers with an annual consumption between 22,000 and 69,999 MWh. Average rates include energy and supply costs, network costs (transmission and distribution), and all applicable taxes including VAT, renewable, capacity, environmental, nuclear, and other levies. Eurostat publishes data twice a year. Average annual rates are reported as part of the data for the second semester.

Industrial demand growth

For each of the 10 jurisdictions, we produced a comparable data set showing industrial electricity demand from the year 2000 to the year 2024 in TWh. Historical industrial data for each jurisdiction includes electricity demand from primary industries such as manufacturing, mining, and oil and gas. Transportation and agricultural energy uses were not included.

For years 2025 onwards, we used the industrial demand projections included in the reference or baseline case as published by each jurisdiction's electricity system operator or the equivalent organization that is responsible for electricity system planning (see Table 2 for list of sources). To ensure consistency and comparability between jurisdictions and across time, we checked that the historical and future scope of what is included under "industrial" demand matches.

In some cases, the starting point for industrial demand in a jurisdiction's electricity system plan did not match the most recent historical value. Using the plan's absolute values directly would have produced an artificial jump or drop between the historical and projected portions of the series, which in turn would have distorted cross-jurisdictional comparisons of growth. To address this, we preserved the growth trajectory implied by each jurisdiction's plan but rebased that trajectory to the most recent year of actual historical data. In practice, this meant calculating the year-over-year percent change in industrial demand from the plan and then applying those growth rates sequentially to the historical endpoint. The result is a continuous series in which projected demand reflects the planner's expected pace of growth without introducing a level shift between observed and projected years.

The data was then normalized to the baseline year 2000 to showcase the change in industrial demand since then and how future demand varies relative to that baseline. See Metric 1: Energy planning for a list of data sources.

Solar and wind capacity additions

For all jurisdictions we identified the growth in solar and wind capacity relative to the year 2015 as well as the absolute capacity in gigawatts added to each grid between 2015 and the latest available year (2024 or 2025).

TABLE 2:

DATA SOURCES FOR SOLAR AND WIND CAPACITY ADDITIONS

Jurisdiction	Source	Notes
B.C., ON, QC	Statistics Canada. Table 25-10-0022-01	
AB	Alberta Electric System Operator (AESO)	Data available up to January 2026
NO, U.K., GER, Canada, Australia, U.S.	Ember	Annual country-level data up to year 2024

Metric 1: Energy planning

The objective of this metric is to better understand how jurisdictions are planning for expected growth in industrial electricity demand and the extent to which their current plans match demand from industrial projects currently waiting to connect.

Gap between industrial demand and system plan

Step 1: We identified each jurisdiction's baseline electricity plan out to 2035 (sometimes called the reference case) from its latest published planning documents as of December 2025. From these electricity plans, we extracted demand attributed to industrial uses, including data centres and hydrogen production. In some cases, planning documents didn't identify the expected future load from *existing* industrial users. In those cases, we assumed their demand would remain constant at the level of the year 2024. This work was carried out in collaboration with Dunsky Energy + Climate Advisors.

Step 2: To determine a jurisdiction's electricity demand from industrial projects waiting to connect to the grid, we gathered data from public sources about each jurisdiction's industrial project queue as of December 2025. We considered industrial projects from sectors including manufacturing, data centres, hydrogen, and large-scale battery storage. Given the limited transparency regarding past completion rates of proposed projects, we consistently assumed a 50 per cent cancellation rate for all projects currently in the queue. This assumption is consistent with the methodology adopted by Texas, based on actual data.

The applied 50 per cent cancellation rate is conservative in that we assume the queue remains static as of February 2026. In other words, we do not assume any projects entering the queue after that date to come online before 2035. This means projected industrial demand growth is likely understated, since some projects announced or queued after February 2026 will almost certainly be built within the forecast window.

Interconnection requests specify a project's maximum interconnection capacity, but most industrial loads operate below that peak. To reflect this fact, we applied different demand utilization factors to different project types in the queue. The demand utilization factor measures how an industrial user's average load compares to its peak load in a given year. Table 3 shows our assumptions for demand utilization factors for different project types.

Step 3: For the final step, we compare the results of step 1 and step 2 to determine the jurisdiction's industrial demand planning gap.

TABLE 3:

INDUSTRIAL PROJECTS DEMAND UTILIZATION FACTOR ASSUMPTIONS

Industrial load type	Demand utilization factor	Rationale and sources
Data centers	80% load factor	Data centres operate continuously, with high baseline server load and cooling demand that tracks IT load closely. AI-focused facilities typically report loads that have lower demand utilization factors than their server utilization rates. Evidence from actual data reported have shown that load factors for data centers ranged between 67 per cent and 90 percent.
Battery storage	20%	When batteries charge from the grid, they are considered a load. We used the assumption based on what is used in NREL's (Annual Technology Baseline) database that a large scale battery charges once per day. We assumed batteries installed are 4-hour duration with 85 per cent round-trip efficiency. So the estimated load factor is 4/24 X .85 =19.6 per cent rounded to 20 per cent.
Other industrial loads	90% load factor	Manufacturing and large industrial plants (such as smelters, refineries, and pulp mills) have consistently high load factors and typically optimize the use of their load over time.

Scoring:

Because the absolute size of the planning gap varies greatly between jurisdictions, we calculated the final score for each jurisdiction based on the ratio between the planning gap and the official system plan. A higher ratio indicates a larger gap relative to the system plan's demand projection and results in a lower overall score. Conversely, a smaller ratio indicates a smaller planning gap and results in a higher score. Table 4 illustrates the final scoring based on this ratio. Table 5 lists all the sources.

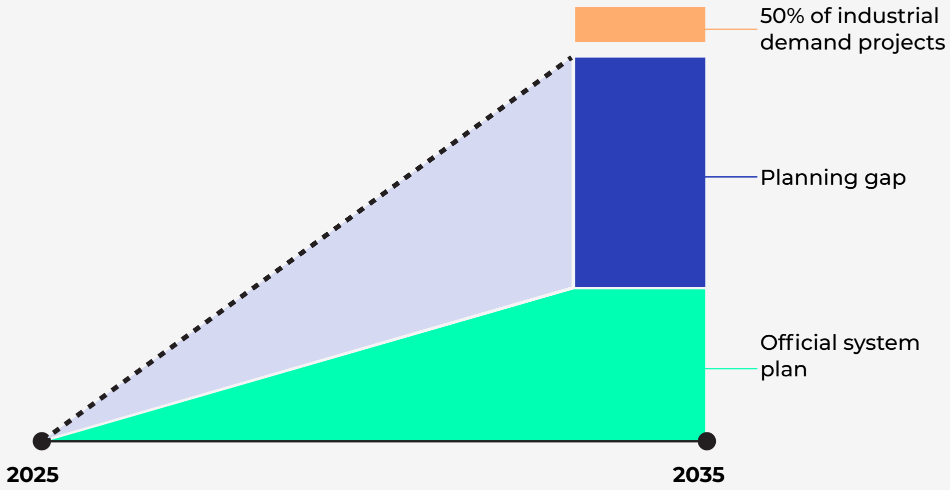

TABLE 4:

ASSESSMENT OF ENERGY PLANNING METRIC

Ratio of planning gap to projected demand in official system plan	Assessment score
>10	1 (= low adequacy of energy planning)
5-10	2
2-5	3
1.5-2	4
<1.5	5 (= high adequacy of energy planning)

Sources:

Table 5 shows the data sources used for this analysis across the ten jurisdictions.

TABLE 5:

DATA SOURCES USED FOR ENERGY PLANNING METRIC

Jurisdiction	Historical data	System plan	Project queue
AB	Statistics Canada. Table 25-10-0030-01	AESO 2024 LTO	AESO project list (as of February 2026)
ON		IESO 2025 APO[1] - Demand forecast module data	Technical Paper on large step loads 2025
B.C.		BC Hydro 2025 IRP - Tables A3, A4	Individual project assessments from the Major Projects Inventory
QC		Hydro-Québec - État d'avancement 2025 - Table 2.1	Hydro-Québec Letter in response to an access-to-information request.
GER	De Statis Table 43531-0001	Network Development Plan 2037/2045	List of load connection requests
TX	Energy Information Administration—State profiles	ERCOT load forecast	ERCOT Load forecast , adjustments to load forecast methodology
WA		Washington State Energy Strategy 2021	
NO	Statistics Norway-Table 14489	Statnett's Long-Term Market Analysis 2024-2050	Flexibility Study
U.K.	Digest of U.K. Energy Statistics (DUKES) 2025 - Table 1.1.5	Future Energy Scenarios: Pathways to Net Zero (November 2025)	NESO detailed connection results (January 2026)
NSW	Department of Climate Change, Energy, the Environment and Water, Australian Energy Statistics, Table G	AEMO 2025 The Electricity Statement of Opportunities (ESOO)	Major project list

Limitations:

This metric provides a snapshot of the planning gap at a specific point in time; in reality the project queue (and thus the planning gap) grows every time a project is added to the queue and shrinks when a project is cancelled. We accounted for expected project cancellations by assuming a universal 50 per cent cancellation rate across all projects in the queue but did not make an assumption about future additions to the queue. As a result, the identified planning gaps are likely conservative.

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[1] APO 2026 was published after this analysis was completed.

Relatedly, we were not able to account for the varying levels of maturity of the projects in the industrial load queue due to a lack of transparent data across jurisdictions. Had this information been available, we would have assigned greater certainty to projects that are further advanced in the queue instead of assuming a 50 per cent cancellation rate across the entire queue.

Finally, jurisdictions also have differing processes for organizing their queues. Some jurisdictions operate with a first-come, first-served approach to building the queue, others prioritize first-ready projects, while others may prioritize or de-prioritize different project types (e.g., Quebec has put limitations on loads for cryptocurrency mining, and Alberta placed a cap on grid-connected data centres). Again, due to a lack of data on the impact of these differences, particularly with the recency of changes in many queue systems, we did not take these differences into consideration. We did acknowledge that the competitive queue process in Quebec, in place since 2023, may have influenced their results.

Metric 2: Flexibility planning

The objective of this metric is to better understand the extent to which jurisdictions are developing modern, flexible grids. To do so, we assessed to what extent each jurisdiction has grown system flexibility over the last 5 years in line with growing solar and wind generation.

Flexibility changes in non-hydro grids (2019-2024)

For each jurisdiction, we estimated total system flexibility in 2019 and 2024 by adding up the flexible capacity, in MW, stemming from five sources:

- **Hydro generation**: Hydro dams have the ability to ramp up generation very quickly to meet rising demand. Normally dams are not operating at full electricity-generating capacity, which gives them inherent flexibility to adjust the generation as grid conditions change both within a given hour and seasonally.
- **Flexible gas**: This includes flexible capacity from simple-cycle gas plants, also known as "peaker" plants, which ramp up to meet short-duration peaks in demand. In our analysis, we also included flexible capacity provided by other forms of fast-ramping combustion-based technologies such as reciprocating engines fueled by gas, oil, or diesel when data was available. We did not include steam-based technologies such as combined-cycle gas plants, as those are often not as flexible as single-cycle plants.
- **Storage:** We include flexible capacity from all types of energy storage such as batteries, pumped hydro, and hydro storage.
- **Imports through interties**: Grid operators frequently use electricity imports from neighbouring jurisdictions to increase supply in the system at times of high demand. We adjusted a jurisdiction's total theoretical import capacity for any technical or rule-based import limitations in practice.

- **Demand response**: Demand response refers to the ability of electricity consumers—industrial, commercial, or residential—to voluntarily reduce or shift their consumption in response to grid conditions or price signals. Rather than increasing available supply, it reduces the load the system must serve during periods of stress. This can substitute for, or complement, the deployment of additional generation capacity during peak periods. Demand response programs take a range of forms (see Metric 5: Industrial rate modernization for more information).

As these five types of flexible capacity are not available at their full capacity throughout the year, we adjusted each one by a technology-specific availability factor. We drew on the work done by the Pembina Institute to reflect variability in availability factors using published availability data from AESO's statistical report and modelling by E3 for AESO.

We calculated the usable flexible capacity by multiplying total capacity from each source by the following availability factors:

TABLE 6:

FLEXIBILITY AVAILABILITY FACTORS BY TYPE (FOR RESERVE MARGIN CALCULATION ONLY)

Flexibility type	Availability factor (per cent)	Source
Hydro generation	67	E3 Study
Imports through interties	50	
Flexible gas	70	AESO
Storage	95	
Demand response	50	

We assumed these availability factors to be consistent across all jurisdictions and over time. Finally, we aggregated results by flexibility type across the 6 non-hydro jurisdictions to identify growth in system flexibility by type between 2019 and 2024.

Flexible capacity relative to peak demand

To assess and compare the adequacy of jurisdictions' flexibility planning, we followed these steps:

Step 1: Take the total available flexibility (in MW) from the previous section for each jurisdiction.

Step 2: Identify peak demand in MW for each jurisdiction for years 2019 and 2024

Step 3: Divide the available capacity for each year by the peak demand

Step 4: Identify the share of solar and wind capacity relative to total installed generation capacity for each jurisdiction for the years 2019 and 2024.

We then mapped the level and trajectory of each jurisdiction's flexibility capacity (normalized by peak demand) to the share of solar and wind between the years 2019 and 2024.

Scoring:

We used a combination of the two numbers in steps 3 and 4 above to arrive at a final assessment score for each jurisdiction. Jurisdictions that scaled their flexibility in step with growing demand and rising wind and solar generation scored highest. See Table 7.

TABLE 7:

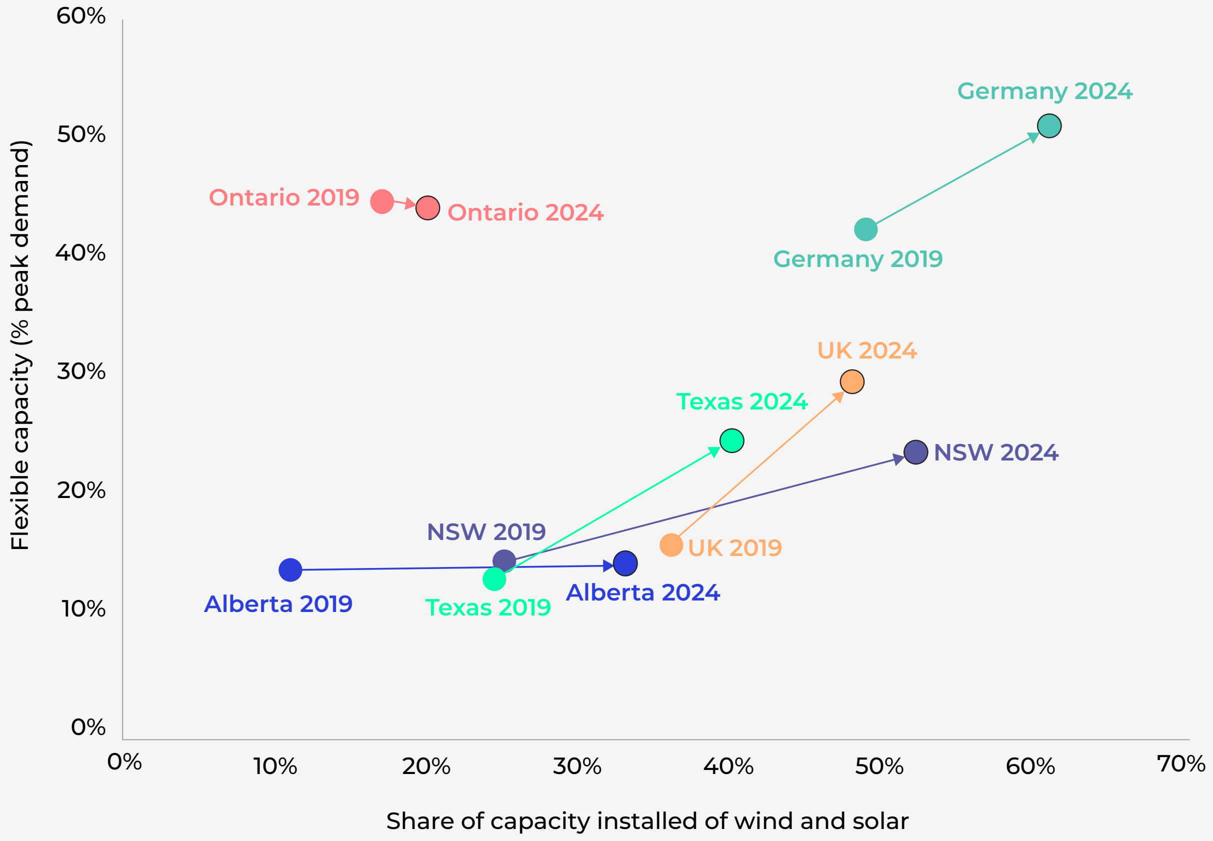
ASSESSMENT OF FLEXIBILITY PLANNING METRIC

Level of flexibility: Flexible capacity (per cent of peak demand) 2019-2024	**Direction of change: Is flexibility growing in proportion with renewables**	**Assessment score**
<20	Flat or decreasing	1 (= low adequacy of flexibility planning)
20-25	Low growth	2
25-30	Moderate growth	3
30-40	High growth	4
>40	Flexibility growth exceeding growth in renewables	5 (= high adequacy of flexibility planning)

Figure 1 highlights the different directions of growth in flexibility across the 6 jurisdictions.

FIGURE 1:

CHANGE IN FLEXIBILITY FOR EACH JURISDICTION OVER TIME RELATIVE TO PEAK DEMAND AND THEIR CHANGING SHARE OF WIND AND SOLAR INSTALLED



Sources:
We collected data for this analysis from a variety of sources across jurisdictions (Table 8). We added the year for sources where the data for the year 2019 is different from the year 2024 to indicate where the data for each year came from.

TABLE 8:

DATA SOURCES FOR FLEXIBILITY ANALYSIS

Jurisdiction	Hydro, flexible gas	Storage	Imports from interties	Demand response	Peak demand
AB	AESO market statistics reports	CanRea 2025 report	AESO	NERC	
ON	IESO Year-End data		IESO (2019), IESO (2024)		
TX	EIA State-Level Electricity Tables		NERC		
U.K.	Plant capacity: (DUKES 5.7)	UK House of commons Library (2024); UK Energy Storage Road map (2019)	UK department of Business, Energy and Industrial Strategy (2019); UK Government (2024)		
GER	Power Plant List	SMARD	ENTSO-e	n/a (no data found)	2019, 2024
NSW	Open electricity portal		AEMO	AEMO	Australia Energy Regulator

Limitations:

We were unable to find reliable growth projections through 2030 or 2035 for all five flexibility sources across all jurisdictions which is why are basing this metric on historical information. However, to compensate for this limitation we discussed known future changes to a jurisdiction's flexibility capacity in the text of the main report.

Metric 3: Transmission planning

The objective of this metric is to better understand the ability of a jurisdiction's electricity grid to deliver electricity from where it is generated to where it is used and to identify the degree to which transmission constraints limit this ability and thus leads to curtailment and waste. Better transmission planning increases a grid's ability to connect supply and demand, leading to less waste in the system.

Observed curtailment over the past five years serves as a primary indicator for this metric. This data was publicly available across the jurisdictions in our study (with the exception of Ontario, see below).

Curtailment is measured as the share of wasted energy in total generation. In other words, it is the ratio of solar and wind energy (in MWh) that was generated but not delivered to customers relative to total solar and wind generation in a given year. We plotted these curtailment rates against each jurisdiction's share of solar and wind capacity for each year from 2021 to 2025.

This approach helped us identify the inflection points in the ten jurisdictions' grids in the study typically saw an inflection point, above which the amount of wasted energy rose rapidly. Some level of curtailment is not only inevitable but also can be economically optimal, as observed in most grids, but a rapid rise is indicative of a structural constraint in the system.

Estimating curtailment for Ontario

Because Ontario does not publish curtailment data beyond the year 2022, we estimated the curtailment values indirectly using reported surplus baseload generation (SBG[2]) and hourly grid conditions highly likely to coincide with curtailment events. Dunsky Energy + Climate Advisors assisted with this approach.

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[2] SBG occurs when electricity production from baseload facilities is greater than Ontario demand.

Step 1: Define curtailment-likely conditions: We assumed curtailment was likely when three simultaneous conditions occurred:

- The Hourly Ontario Energy Price (HOEP) was at or near zero;
- Export intertie capacity was fully utilized; and
- Ontario's hourly electricity demand was fully met.

When all three conditions hold at the same time, the system has surplus generation with no outlet—the defining circumstance under which curtailment occurs.

Step 2: Apply conditions across years: For each year in the study period, we calculated the share of hours in which all three conditions were simultaneously met. This percentage served as the proxy curtailment rate for that year.

Step 3: Validate against a reported benchmark: We cross-checked our results against published curtailment data for years 2021 and 2022. This was particularly important as step 1 conditions focus on system-wide constraints rather than localized issues.

We compared our estimates (A), in MWh, against published curtailment totals (C) for 2021 and 2022 where total curtailment (C=A+B). The gap—which includes localized congestion (B)—ranged from 3% to 9% of A. We applied the lower bound as a fixed correction, giving C = A × 1.03 (e.g., 1,000 GWh × 1.03 = 1,030 GWh). We then divided C by total annual demand (E) to express curtailment as a share of supply: D = C / E (e.g., 1,030 / 150,000 GWh ≈ 0.69%). D is the figure reported for each year in the study period.

Scoring:

The location of the inflection point and the overall trajectory of wasted energy between 2021 and 2025 informed our assessment of the quality of a jurisdiction's transmission planning. A high assessment score indicates better planning, while a lower score indicates less adequate transmission planning (Table 9).

TABLE 9:

ASSESSMENT OF FLEXIBILITY PLANNING METRIC

Share of wasted energy (per cent)	The share of solar and wind capacity at which the inflection point occurs	Assessment score
-	No inflection point	Not applicable
> 15	<20	1 (= low adequacy of flexibility planning)
15-12	20-30	2
12-8	30-40	3
8-5	40-50	4
< 5	> 50 or reversed trend of increasing wasted energy	5 (= high adequacy of flexibility planning)

Sources:

Table 10 lists the data sources we used for this metric.

TABLE 10:

DATA SOURCES FOR THE TRANSMISSION PLANNING METRIC

Jurisdiction	Solar and wind Capacity	Curtailment	Notes
AB	Statistics Canada. Table 25-10-0022-01	Market Surveillance Administrator - Quarterly reports	No data on curtailment prior to 2022
ON		See calculation	
QC		No data available	Due to the low share of solar and wind in these jurisdictions, we found that curtailment values are likely low. We found evidence that in Washington for example, curtailment between 2008 and 2024 was 0.17%
B.C.			
NO			
WA	eia state electricity profile - Table 4A	Grid Lab Study (March 2025)	
TX	eia state electricity profile - Table 4A	State of The Market Report - ERCOT	
NSW	Open electricity		
GER	SMARD	SMARD	
U.K.	Digest of UK Energy Statistics (DUKES) 2025 - Table 5.2	NESO - Balancing Cost Report 2024/2025	

Limitations:
A more complete measure of transmission constraints would incorporate congestion costs and the share of hours in which power prices fall to low or negative levels—both indicators of a system under stress. Data for these elements was not available across all jurisdictions, so observed curtailment serves as the primary proxy. Where congestion cost data was available, it was often reported as a system-wide aggregate rather than attributed to curtailment specifically, making direct comparison unreliable. Future iterations of this metric could incorporate these additional elements as reporting practices mature.

New ways to measure transmission constraints in some of the systems in our study are also emerging. Some jurisdictions, such as Ontario, have recently introduced locational marginal pricing. This is a method of pricing electricity that varies by location on the grid, making transmission bottlenecks directly visible in price signals. Initial data highlights system bottlenecks at a given moment in time but it is too new to be a reliable indicator for this study and is not comparable across systems without such a signal.

Transmission investment

The transmission investment figure included costs of publicly available investment plans for transmission up to the year 2035. We excluded distribution investment or other operational costs for existing assets as far as practical. Cost data reported in other currencies was converted to Canadian dollars based on the Bank of Canada exchange rates. Table 11 summarizes the data sources used.

TABLE 11:

TRANSMISSION INVESTMENT SOURCES

Jurisdiction	Total investment	Size of transmission system (circuit-KMs)	Notes
AB	AESO 2025 Long-Term Transmission Plan	AESO	
B.C.	BC Hydro service plan 2026-2029	BC Hydro	Assumed a similar level of investment in years 2030-2035 based on average spending in years 2026-2029. We assumed 40% of the investment goes to transmission and 60% to distribution. Assumed the total investment for the NCTL project to be 6 billion by 2035.
ON	Hydro One	Hydro One	Assumed an additional 5,000 circuit kilometres managed by others outside Hydro One.
QC	Hydro-Québec 2035 Action Plan	Power and Telecom	
TX	ERCOT 2024 regional transmission plan	ERCOT	
U.K.	NESO - Beyond 2030	National Grid	
GER	Network Development Plan Electricity	netztransparenz.de	
NO	Statnett 2025 system development plan	Energy Facts Norway	
NSW	Transgrid - Transmission projects	Transgrid	
WA	Bonneville Power Administration—2025 Annual report	Bonneville Power Administration	

Metric 4: Electricity procurement

The objective of this metric is to better understand to what extent the ten jurisdictions' electricity procurement conditions offer investors in renewable generation predictable market access, sizable market volume, and price certainty. Based on expert interviews, including with renewable energy generators, we identified market access, sufficient volume and price certainty as critical to investors.

To examine and compare the electricity procurement conditions across the ten comparator jurisdictions we first distinguished between jurisdictions with procurement-based electricity markets and those with open markets (Table 12). In procurement-based markets, generators can only enter the market to sell power when a procuring agency (e.g., crown utility, system operator, or government) issues procurement calls for new generation. In open markets, generators can build and connect to the grid whenever they choose to, so long as they acquire the appropriate permits. The following table identifies which group each jurisdiction belongs to and why.

TABLE 12:

PROCUREMENT-BASED ELECTRICITY MARKETS VS. OPEN MARKETS

	Procurement-based markets
B.C.	BC Hydro is the main authority for issuing Calls for Power and managing the contracts. FortisBC also has authority to issue calls and manage contracts, but only recently ran its first-ever procurement call in 2025, which remains ongoing.
ON	IESO is the authority for issuing the request for proposals and managing the contracts, and does so at the directive of the Government of Ontario.
NO	The Government of Norway is the authority for issuing electricity generation tenders and managing the contracts.
WA	Independent utilities have the authority to issue tenders on an "as needed" basis and manage their own contracts.
QC	Hydro-Quebec is the authority for issuing tenders and managing the contracts.

	Procurement-based markets
NSW	Because NSW is connected to the National Grid in Australia, tenders are run at two levels: state and national. The two levels of government co-ordinate to ensure no two tenders are running at the same time. The AEMO runs tenders at both levels, with the contracts signed either by the Financial Trustee (Equity Trustees LTD) (at the state level) or the Commonwealth Government (at the national level).
GER	The Federal Network Agency (Bundesnetzagentur) is the authority for issuing tenders, selecting the bids, and providing the successful bids with an "Zuschlag" (award notice). Transmission system operators are then required to pay the successful bids the market rates. The transmission system operators work with the federal government to balance any difference between the market price and the strike price in the approved bid.
U.K.	The U.K.'s Contract for Difference allocation rounds are run by the National Grid Electricity System Operator with the Low Carbon Contracts Company signing and managing the resulting contracts.
	Open markets
AB	Independent power producers can build anytime, but must first submit a connection request to Alberta Electric System Operator, and then get approval from Alberta Utilities Commission.
TX	Independent power producers can build whenever they want, but must first submit a connection request to the Electric Reliability Council of Texas (ERCOT), and obtain permits from different specialized agencies.

Market access

Market access is defined as the frequency at which new renewable energy generators are able to enter the market and sell electricity to the grid. For procurement-based markets, where entry is controlled by procuring agencies, we reviewed the websites of crown utilities, system operators, and governments to document all procurement calls held over the past five years up until April 2026. The CanREA Procurement Calendar served as a starting point for identifying procurement calls in Canadian jurisdictions. We then calculated the observed procurement frequency, i.e., the length of time between procurement calls. Next, we defined three categories of observed procurement frequency across the procurement-based markets:

- As-needed or sporadic
- Every two to three years
- Annual or more frequent

We classified jurisdictions with open markets automatically in the third category (annual or more frequent).

Finally, we assigned these three categories scores from 1 to 5, where a score of 1 implies sporadic observed procurement and therefore low market access. In contrast, a jurisdiction with annual or more frequent procurement in the past received a score of 5, indicating high market access for renewable generators. See Table 13 for an overview of the scoring system.

TABLE 13:

ASSESSMENT OF MARKET ACCESS ACROSS JURISDICTIONS

Observed procurement frequency over the past 5 years	Score for assessing a jurisdiction's market access
Sporadic	1 (= low degree of market access)
Every 2-3 years	3
Annual or more frequent	5 (= high degree of market access)

Market volume

We defined a jurisdiction's market volume as the new renewable electricity capacity (MW) added to the grid in a given year.

To calculate market volume in procurement-based markets, we averaged total procurement targets across all new build calls over the past five years.

For open markets, we averaged the annual new renewable electricity supply (solar and wind only) connected to the grid over the past five years. We collected data on annual renewable capacity additions from system operators' statistics, such as AESO Market Statistics.

We found that market volume varies significantly across the ten jurisdictions. We used the buckets shown in Table 14 to represent the distribution of market volumes across the jurisdictions. Since larger procurement volumes are more attractive to investors, the jurisdictions in the bucket with the largest procurement volumes received a score of 5, while those in the bucket with the smallest volumes received a score of 1 .

TABLE 14:

ASSESSMENT OF MARKET VOLUME ACROSS JURISDICTIONS

Average procurement or newly connected supply over the past 5 years (MW)	Score for assessing a jurisdiction's market volume
≤200	1 (= low market volume)
201-600	2
601-1000	3
1001-1400	4
1401-7800	5 (= high market volume)

Price certainty

Price certainty is defined as the extent to which renewable electricity generators are able to predict the price they will receive for the electricity they produce over a project's lifetime. Price certainty largely depends on the types of contract that power purchasers (public agencies or private corporations) use to procure power from generators.

Table 15 shows the different contract types and our assessment of the price certainty that each contract type provides for generators.

TABLE 15:

PRICE CERTAINTY CONTRACT CLASSIFICATION

Contract type	Notes	Score for assessing price certainty for generators
Spot market	Generators sell on wholesale electricity markets where prices fluctuate with market prices.	1 (= low price certainty)
Corporate power purchase agreements	Generators sell at a predetermined price to corporate users but these contracts typically have shorter durations (on average 15 years) and involve higher counterparty risk.	3
Utility-led power purchase agreements	Long-term contracts between generators and utilities, where the generator commits to supplying a fixed volume of electricity at an agreed price. These contracts typically run for 20 to 30 years, providing revenue certainty for generators and stable supply costs for utilities.	5 (= high price certainty)
Contracts for difference	One-way contracts for difference, typically signed with governments or system operators, pay producers when market price falls below the agreed price. Two-way contracts for difference do the same, but producers repay when the market exceeds that agreed price. Two-way contracts deliver equal price certainty for investors compared with one-way but with added benefit to taxpayers. These contracts typically run for 15 to 20 years.	5 (= high price certainty)

To assess a jurisdiction's price certainty for renewable power generators, we determined the primary contract type available to generators in each jurisdiction, based on available data. In procurement-based systems, information on the types of contracts offered is included in procurement call documents. The data is less accessible in open market systems, where power is typically sold through bilateral contracts between generators and corporate users. For these markets, we drew information on contract types from research databases, such as the Business Renewable Centre and estimates from other publicly available sources.

Scoring:

To determine a jurisdiction's overall performance on electricity procurement, we then averaged a jurisdiction's scores for market access, market volume, and price certainty. We weighed the three market conditions equally because interview findings indicated that all three together are enabling conditions for renewable energy investment. In practice, the relative importance of each procurement condition may be different for different investors, depending on a jurisdiction's policy context and investors' risk appetite.

TABLE 16:

DATA SOURCES FOR ELECTRICITY PROCUREMENT

Jurisdiction	Source
AB	AESO Market Statistics on Alberta's Renewable Capacity
B.C.	BC Hydro's 2024 and 2025 Call for Powers
GER	Bundesnetzagentur (Federal Network Agency) 2020-2025 auctions
NO	Utsira Nord and Sørlige Nordsjø
NSW	AEMO Services Limited NSW-level auctions and National Energy Market-level auctions 2020-2025
ON	IESO's Long-Term 2 Request for Proposal 2025
QC	Hydro Quebec's 2021-2025 Call for Tenders
TX	ERCOT's Capacity Changes by Fuel Type Data Set
U.K.	Department for Energy Security and Net Zero Allocations 2021-2025
WA	Independent utility-led request for proposals on an as needed basis, some examples include Puget Sound Energy (2024), Avista (2025), and Grant County Public Utility District (2024).

Limitations:

A few methodological considerations and caveats that shape interpretation of the results:

- Procurement data is only considered up to April 20, 2026. The assessment for Canadian provinces can quickly change as some provinces have recently started increasing the frequency of their procurement calls (for example, B.C. and Ontario).
- Equal weighting of the three market conditions is a simplifying assumption. Investors with different risk profiles or priorities may

reach different conclusions about the relative importance of the three conditions for a jurisdiction’s attractiveness.

- We only considered the dominant contract type to assess a jurisdiction’s price certainty for renewable power generators. Jurisdictions offering a variety of contracts to generators may attract different investors with diverse risk profiles. However, this potential value of jurisdictions offering a diversity of contract types to different investors is not captured in the analysis.

Metric 5: Industrial rate modernization

The objective of this metric is to better understand how jurisdictions leverage industrial rate incentives (discounts and/or payments) to reduce demand on the grid during peak times. For energy-intensive industries with flexible operations, these incentives can translate into material reductions in annual electricity costs, improving their competitiveness and making the jurisdictions that offer them more attractive destinations for industrial investment. To that end, we identified industrial rate incentive programs across the ten jurisdictions and identified their impacts on both industrial electricity bills and on system peak demand (measured in terms of MW reduced during the top annual peak demand hours). The research and analysis for this work was done in partnership with Utilis Consulting.

To begin this analysis, we identified current industrial rate incentive programs for each jurisdiction. We examined program documents issued by utilities, system operators, regulators and other third-party analyses of these programs to better understand how they work.

We found that many jurisdictions operated multiple rate incentive programs open to industrial users. We focused our analysis on the primary industrial rate incentive programs in each jurisdiction that most directly targeted the reduction of *annual* peak demand. This is because electricity infrastructure must be built to meet annual peak demand, making peak demand the key driver of system costs.

Our research also showed that reducing daily peak demand does not necessarily reduce annual peak demand. For example, programs such as time-of-use, locational marginal price, and capacity markets provide more continuous signals that influence daily consumption patterns throughout the year, rather than reducing the critical annual peak hours that drive system costs. For this reason, we prioritized programs that focus on annual peak demand over these alternative tools.

We then used a three-step framework to assess each jurisdiction's primary program on two outcomes: its effect on system peak demand and its effect on industrial electricity bills (see Tables 17 and 18).

Step 1: Assess each impact individually. Most jurisdictions published quantitative data on peak demand reductions linked to industrial rate incentives. However, quantitative data on the average bill reductions for participating industries was publicly unavailable for many jurisdictions. Where such data was unavailable, we estimated the impacts based on the design characteristics of the policy instrument and supporting literature.

To compare impacts across jurisdictions, we defined five ranges (in per cent) for the achieved peak demand reductions and bill reductions respectively. We defined these ranges to achieve a roughly even distribution of jurisdictions across them, while also ensuring meaningful distinctions between values. Because peak demand and reduction of bills have different distributions, the ranges across these two impacts are not identical.

Then we assigned the five ranges assessment scores on a scale from 1 to 5. Larger peak demand reductions received higher scores because they indicate increased benefits to the grid from the industrial rate incentive program, while larger industrial bill reductions received higher scores because they indicate increased competitiveness for industrial customers (see Tables 17 and 18).

TABLE 17:

ASSESSMENT OF THE IMPACTS OF INDUSTRIAL RATE INCENTIVE PROGRAMS ON SYSTEM PEAK DEMAND ACROSS JURISDICTIONS

Demand reduction during top annual peak hours (per cent) as a result of a jurisdiction’s primary rate incentive program for industrial users	Assessment score
0-3	1 (= low impact)
4-5	2
6-15	3
16-40	4
>40	5 (= high impact)

TABLE 18:

ASSESSMENT OF THE IMPACTS OF INDUSTRIAL RATE INCENTIVE PROGRAMS ON INDUSTRIAL ELECTRICITY BILLS ACROSS JURISDICTIONS (ESTIMATED)

Assessment	Per cent of bill reduction (estimated)	Assessment score
Low (2)	~0	1 (= low impact)
Low/medium (4)	1-5	2
Medium (6)	6-10	3
Medium/high (8)	11-20	4
High (10)	>20	5 (= high impact)

Step 2: Check alignment between the impacts. We assessed the alignment between a program's impact on peak demand (i.e. its system-wide benefits) and its impact on bills (i.e. its benefits for industrial users). Ideally, the benefits to industrial users are in proportion to the system-wide benefits.

This was done by calculating the absolute difference between the two impacts.

- If the difference is 3 or more, the program receives a combined score of **1**. E.g., *Germany: 4 (impact on industrial bill) - 1 (impact on system annual peak) = 3* → **1**
- If the difference is less than 3, we proceed to **Step 3**

  E.g., Alberta: *2 (impact on industrial bill) - 2 (impact on system annual peak) = 0* → **Step 3**

This approach ensured that programs that were heavily misaligned could be differentiated from those that had more balanced impacts across peak demand and bill reduction.

Step 3: Score based on the weaker impact. If the difference was less than 6 points, a combined score was assigned based on the lower of the two values. Programs needed to perform well across both impacts to receive a high rating.

If the lower of the two values is	Give a score of
Low (1)	2
Low/medium (2)	3
Medium (3)	4
Medium/high (4)	5
High (5)	5

TABLE 19:

PERFORMANCE OF JURISDICTIONS ON INDUSTRIAL FLEXIBILITY RATE INCENTIVES

Jurisdiction	**Industrial peak demand reduction program**	**Peak demand reduction**		**Bill reduction**		**Combined score**
		Per cent reduction = MW peak demand reduction/total MW industrial demand	Score	Per cent reduction (estimated)	Score	1 = low performance on industrial rate incentives; 5 = high performance on industrial rate incentives
AB	12 Coincident Peak Program	4	2	1-5	2	3
GER	Individual Grid Charges (Even Grid Usage STROMNEV)	2	1	16-20	4	1
ON	Industrial Conservation Initiative	33	4	11-15	4	5
QC	Hydro Quebec Demand Response Commitment Option	7	3	1-5	2	3
TX	Four Coincident Peak Program	1	1	1-5	2	2
NSW	Peak Demand Reduction Scheme	6	3	1-5	2	3
NO	Interruptible load contracts between industry and DSO	Aggregate data about DSO contracts is publicly unavailable. But, Statnett's 2015 capacity adequacy study suggests 400-700MW of interruptible loads was available under the previous tariff regulation, before such arrangements were phased out with the shift to cost-reflective, non-discrimantory tariffs.	3*	Data not publicly available as it differs across DSOs. One example can be found here.	2*	3
B.C.	Does not have **dedicated** industrial peak demand reduction incentives (i.e., outside of standard mechanisms such as demand charges or TOU rates)					
WA						
U.K.						

* based on estimates

Limitations:
This approach only considers a jurisdiction's primary industrial rate incentive program, although many jurisdictions offer multiple incentives that can interact to shape electricity consumer behaviour.

Moreover, precise bill impacts from industrial rate incentives are not publicly available, so we drew on a combination of theoretical assumptions and qualitative information to estimate their effects.

Cross-subsidization between different groups of ratepayers

We used cost-revenue-ratios to identify the degree to which electricity users groups pay more or less than the system costs they cause.

Electricity system costs are allocated differently across jurisdictions, but most regulators follow a common underlying principle: customers should pay the costs they cause the system. This is known as cost causation, and it applies across all customer classes—residential, commercial, and industrial. Regulators typically assess how closely rates align with this principle using a revenue-to-cost ratio, which compares the revenues collected from each customer class to the costs that class imposes on the system.

When a class consistently pays more or less than its cost of service, the difference is borne by other ratepayers, known as cross-subsidization. A revenue-to-cost-ratio above 100 per cent means that the group pays more for its electricity than it costs the system to deliver that electricity, which implies cross-subsidization from other user groups. Conversely, a ratio of less than 100 per cent means that the specific group receives cross-subsidization from others. A ratio of 100 per cent means the group pays the equivalent cost of serving them (cost-causation). Differences in this ratio reflect the extent to which jurisdictions hold to the principle of cost causation.

Revenue-to-cost-ratios are typically reported in utility program evaluations, system operator reports, or regulatory filings, and we used these sources to inform this analysis. We found that NSW, Norway, and U.K. approach cost allocation differently from traditional revenue-cost-ratio calculations, so we positioned them using adjusted methods to ensure comparability with other jurisdictions:

- NSW uses the stand-alone and avoidable cost band test which compares the revenue collected to a reasonable range of costs. If the revenue is too low, it means the group is not covering its costs.

If the revenue is too high, it means the group may be paying more than its fair share. If the revenue falls within the "acceptable range", the group is covering the costs for themselves only. We attributed this outcome a ratio of 100 per cent in our assessment, reflecting that the Australian Energy Regulator considers this band an appropriate distribution of costs across the group.

- Norway has a fixed-tariff principle where revenue collected to maintain the grid needs to be objective and non-discriminatory (ratio = 100 per cent).
- The U.K. primarily recovers grid costs through fixed charges which differ for industrial and non-industrial consumers based on their respective consumption patterns. Because costs are broadly allocated according to each group's total share (60 per cent industrial and 40 per cent non-industrial), there is limited cross-subsidization between groups (ratio = 100 per cent).

Overall these ratios are indicative rather than definitive. They reflect the relative cross-subsidization experienced by certain industrial customers at specific points in time and may not always be directly comparable across jurisdictions due to differences in calculation methodology, timing, customer type, and bill components included.

TABLE 20:

DATA SET UNDERLYING THE SHARE OF INDUSTRY COSTS TO THE POWER GRID PAID BY INDUSTRY

Jurisdiction	Cost allocation indicator	Ratio (per cent)	Year	Source
AB	Revenue-cost-ratio	100	2019	Summary of AUC Decision 24820-D01-2020
TX	Revenue-cost-ratio	111	2022	CPS Energy's cost allocation study (one utility only, may not be representative of Texas as a whole)
GER	Data publicly unavailable			
NSW	Stand-alone vs avoidable cost band test	100	2025	Ausgrid's tariff structure submission to AER (one distributor only, may not be representative of NSW as a whole)
ON	Revenue-cost-ratio	97.2	2025	Toronto Hydro's OEB compliance submission (one utility only, may not be representative of Ontario as whole)
U.K.	Volumetric charges	100	2025	Ofgem's energy system cost allocation and recovery review
B.C.	Revenue-cost-ratio	98.5	2024	BC Hydro's cost of service study submission to BCUC
QC	Revenue-cost-ratio	114.3	2023	Calculated by P.O Pineau using Hydro Quebec data (reflects the author's interpretation of Hydro Quebec figures rather than directly reported utility data)
NO	Fixed-tariff	100	Unknown	Norwegian Ministry of Energy's regulation of grid operation's summary
WA	Parity-ratio	100.8	2025	WUTC's final order in Puget Sound Energy's general rate case

Electricity system subsidies funded by taxpayers

We used industrial subsidy program data to identify the degree to which governments use tax revenues to subsidize electricity system costs and lower rates for various user groups.

System costs can be subsidized by taxpayers rather than – or in addition to – ratepayers. Under this approach, the general tax base (i.e., all taxpayers) bears a greater burden through increased taxes while benefits flow to specific ratepayers such as residential, commercial, or industrial customers, depending on who the subsidy targets. However, financing grid expansion through public funding (i.e., taxes) carries its own economic costs, including increased public debt and thus should be used under certain circumstances.

In this analysis, we identified subsidies given to the industrial ratepayers. For data collection across the ten jurisdictions, we first conducted a literature review using the following keywords: “industrial” AND “electricity” AND “rebate” OR “tax”, in addition to the jurisdiction’s name.

We then used the following criteria to identify eligible industrial subsidies:

- Automatic application: We excluded programs that require industrial users to opt-in or that are contingent on industrial users meeting specific criteria.
- Active as of April 2026: We only considered subsidies in place as of April 2026.

For all eligible subsidies, we then identified their impacts on industrial bills (Table 21). Government and utility sources provided estimated average bill reductions across industrial user groups, which were then assigned to ranges of 0-5 per cent, 5-10 per cent, 10-15 per cent, and 15-20 per cent. We report ranges rather than precise figures, given that bill compositions vary across jurisdictions. The data should therefore be interpreted as illustrative of broad trends rather than precise cross-jurisdictional comparisons.

TABLE 21:

DATA SET UNDERLYING THE PERCENTAGE OF INDUSTRIAL POWER BILLS SUBSIDIZED BY TAXPAYERS

Jurisdiction	Subsidy policy or program	Bill Component	Bill reduction (per cent)	Source
GER	Strompreise (electricity price brake)	Reduced network charges ("grid fees")	10-15	German Government's energy price relief measures announcement
ON	Renewable Generation Subsidy Program	Reduced electricity price	15-20	Financial Accountability Office of Ontario's report on renewable generation subsidy program
B.C.	B.C. Electricity Affordability Credit	Electricity rebate, automatically calculated and applied to BC Hydro bills	0-5	BC Hydro electricity affordability credit information page
WA	Credit—Sales of electricity or gas to an aluminum smelter	Reduction in electricity taxes	0-5	Revised Code of Washington 82.16.0498
NO	Electrical Power Tax	Reduction in electricity taxes (consumption tax) at the industry level	Data not publicly available	Data not publicly available
AB	None			
TX				
NSW				
U.K.				
QC				

Metric 6: Climate policy certainty

The objective of this metric is to better understand the extent to which jurisdictions offer clean electricity investors predictable climate policy. For the purpose of this analysis, we define climate policy to include both a specified target (typically, but not necessarily expressed as a reduction of GHG emissions by a certain year compared to a baseline) and actions for how to achieve this goal (broadly aligned with Sokolowski and Heffron (2022)). Since our focus is on policy certainty, we only considered legally binding targets for decarbonization of both the electricity sector and the wider economy and *implemented* programs—rather than non-binding government announcements, aspirations, strategies, or action plans.

We qualitatively assessed a jurisdiction's climate policy certainty (i.e., the predictability of targets and programs) for clean electricity investors based on two indicators:

1. Policy certainty "on the books". This indicator identifies the extent to which a jurisdiction has put in place legally binding, long-term (i.e. 2040-2050) decarbonization targets and implemented policy instruments to achieve these targets. Long-term decarbonization targets include economy-wide targets and electricity sector targets. Implemented policy instruments aim at incentivising investment in clean electricity (e.g., carbon pricing policies, feed-in-tariffs, offset protocols, tax incentives).
2. Historical policy stability. This indicator considers the stability of a jurisdiction's targets and policy instruments over the past decade. Stability implies the absence of substantive policy changes or reversals that affect clean electricity project economics. Historical policy stability can be an indicator of future stability. Investors may discount the durability of current targets and instruments "on-the-books" if the jurisdiction has experienced instability in the past.

Scoring:

We assessed a jurisdiction's performance across these indicators, using the following framework:

Does the jurisdiction have a legislated target for economy-wide decarbonization?

✓ means that an explicit, legally binding, long-term target (i.e. 2040-2050) exists
✗ means that no legally binding, explicit target exists

Note: non-binding targets and targets implicit in policy instruments and programs are not considered here.

Does the jurisdiction have a legislated target for the decarbonization of the electricity sector?

✓ means that an explicit, legally binding long-term target (i.e., 2040-2050) exists
✗ means that no legally binding, explicit target exists

Note: non-binding targets and targets implicit in policy instruments and programs are not considered here.

Do one or more policy-driven incentives exist to mobilize investment into wind, solar, and battery projects?

✓ means at least one policy-driven incentive is in force
✗ means that no high-impact policy-driven incentive is currently in force

Note: We do not identify all policy instruments in force in the jurisdiction.

Assessment of a jurisdiction's policy certainty "on the books":

High certainty "on the books" means that all three elements are in place: an economy-wide target, a sector-specific target, and at least one implemented policy instrument.

Medium certainty "on the books" means that two out of the three elements are in place.

Low certainty "on the books" means that one or zero elements are in place.

How stable have targets (economy-wide and sector-specific) and implemented policy instruments been over the past decade in the jurisdiction?

High stability means that targets and policy instruments have not been subject to substantive changes between 2016 and 2026.

Medium stability means that there have been some changes to targets and instruments in the past decade.

Low stability means that substantive changes to targets and policy instruments have created instability and uncertainty for investors between 2016 and 2026.

Assessment of a jurisdiction’s overall climate policy certainty:

Weighing a jurisdiction’s policy certainty “on the books” and historical policy stability equally to identify overall level of climate policy certainty on a five-point scale:

Certainty “on the books”	Historical policy stability	Assessment score for climate policy certainty (1 = low certainty; 5 = high certainty)
low	low	1
low	medium	2
low	high	3
medium	low	2
medium	medium	3
medium	high	4
high	low	3
high	medium	4
high	high	5

TABLE 22:

POLICY CERTAINTY FOR INVESTORS IN WIND, SOLAR, AND BATTERY PROJECTS ACROSS JURISDICTIONS

	Policy certainty “on the books”				Historical policy stability	
	Economy-wide target	**Electricity sector target**	**Implemented policy instrument**	**Assessment of a jurisdiction’s policy certainty “on the books”**	**Stability of targets and instruments between 2016 and 2026**	**Assessment score of a jurisdiction’s overall climate policy certainty**
	yes ✓ / no ✗			**low / medium / high**		
Ontario	✗	✓	✓	medium	low	2
Alberta	✗	✗	✓	low	low	1
B.C.	✓	✓	✓	high	medium	4
Québec	✓	✓	✓	high	medium	4
Germany	✓	✓	✓	high	high	5
U.K.	✓	✓	✓	high	high	5
Texas	✗	✗	✗	low	medium	2
Washington	✓	✓	✓	high	low	3
Norway	✓	✗	✓	medium	medium	3
New South Wales	✓	✓	✓	high	medium	4

Data sources:

Data sources for this analysis included:

- Legislations and regulations in the ten jurisdictions
- Climate/energy policy databases, including: C2P2, U.S. Climate Alliance Climate Policy Database, State Climate Policy Dashboard, IFCMA Climate Policy database, Ember’s 2030 Global Renewable Target tracker, and Climate Change Laws of the World
- Academic and grey literature
- Media reports

See below the full data set underlying the assessment of the ten jurisdictions.

ONTARIO

OVERALL SCORE: 2

Policy certainty “on the books”: medium

Economy-wide decarbonization target: ✗

Provincial: No explicit target.

Federal: National targets cemented in the Net Zero Emissions Accountability Act do not impose binding provincial targets.

Electricity-sector decarbonization target: ✓

Provincial: No explicit target exists at the provincial level.

Federal: The Clean Electricity Regulations require net-zero electricity systems by 2050.

Policy instrument(s): ✓

Provincial: The Ontario Emissions Performance Standards (EPS) cover large emitters in the electricity generation sector. It came into effect in 2022, replacing the federal OBPS which was in force from 2019 to 2021.

Federal: The Clean Electricity Regulations require emissions reductions on electricity generated from fossil fuels starting in 2035.

The Clean Technology ITC is a refundable tax credit of up to 30% capital invested in clean electricity generation, energy storage, low-carbon heating and certain zero-emission equipment.

Historical policy stability: low

ON has seen substantive, immediate changes to targets and policies over the past 10 years that have negatively affected investment in wind and solar projects.

In 2016, the Climate Change Mitigation and Low Carbon Economy Act (2016) legislated new emissions reduction targets and established a cap and trade system. The emissions reduction targets were: 15 percent by 2020, 37 percent by 2030, and 80 percent by 2050 against a 1990 baseline.

In 2018, the Cap and Trade Cancellation Act reversed the policy without returning credit payments to participating electricity generators. It also required the Ontario government to set emissions reduction targets and develop a climate change plan.

In November 2025, the government repealed the requirement for setting a target, following audit reports that ON would miss its 2030 target (30 percent reduction below 2005 baseline) by a significant margin.

ALBERTA

OVERALL SCORE: 1

Policy certainty “on the books”: low

Economy-wide decarbonization target: ✗

Provincial: AB’s Emissions Reduction and Energy Development Plan includes the “aspiration” to achieve a net zero economy by 2050 but no legal commitment.

Federal: National targets cemented in the Net Zero Emissions Accountability Act do not impose binding provincial targets.

Electricity-sector decarbonization target: ✗

Provincial: The Renewable Electricity Act (2020) stipulates the target to achieve at least 30% electricity produced from renewable energy resources by 2030; no 2050 target exists.

Federal: In May 2026, Alberta and the federal government signed an implementation agreement of their memorandum of understanding from November 2025 which upholds the suspension of the CER in the province pending the on-going court challenge.

Policy instrument(s): ✓

Provincial: The Technology Innovation and Emissions Reduction (TIER) Regulation, established in 2019, is a large emitters carbon trading scheme and Albera’s main tool for driving emissions reductions in industrial and power sectors. Under TIER, renewable electricity generators can generate emissions reduction credits which they can sell to large emitters to create an additional revenue stream.

Federal: Clean Technology ITC is a refundable tax credit of up to 30% capital invested in clean electricity generation, energy storage, low-carbon heating and certain zero-emission equipment.

Historical policy stability: low

Alberta has seen substantive, immediate changes to decarbonization targets, incentives, and their implementation over the past 10 years that have negatively affected investment in wind and solar projects.

While the TIER framework had been mainly stable since its inception (including the long-standing nature of solar and wind offset protocols), in May 2025, the Alberta government froze headline price at $95/t, i.e. TIER is not going along with the annual increase of the federal backstop by $15.

In September 2025, amendments to the TIER regulation included the introduction of compliance through direct investment and the possibility for smaller emitters to opt out of the system, which overall weakened the incentives for wind and solar investment.

The implementation agreement for the Canada-Alberta Memorandum of Understanding from November 2025 defined a trajectory for industrial carbon prices through 2040 but price signals are overall weaker than previously indicated.

Regarding renewable specific changes, in August 2023, without amending the decarbonization target for the electricity sector itself, the Alberta government slowed its implementation. The government implemented a 7-month moratorium of approvals of large wind and solar projects, citing land use and conservation concerns. Since then project cancellations are still common and regulatory uncertainty for renewable investors remains high. In late 2024, the government introduced “no go” zones for wind and solar projects to protect agricultural lands and limit visual impacts.

Regarding Alberta’s policy co-ordination with the federal government, in May 2025, the AB challenged the constitutionality of the federal CERs in the AB Court of Appeal. In November 2025, the government temporarily suspended the regulations immediately in November 2025, and the MOU implementation agreement between Alberta and the federal government extended the regulations’ suspension while Alberta’s court challenge of the regulations is on-going.

Largely due to policy uncertainty (partly driven by uncertainty over future TIER prices and the government’s anti-renewable rules) investment in wind and solar projects in AB dropped to nearly zero in 2025, falling by 99% from 2023 levels.

BRITISH COLUMBIA

OVERALL SCORE: 4

Policy certainty “on the books”: high

Economy-wide decarbonization target: ✓

Provincial: The Climate Change Accountability Act stipulates a 40% economy-wide emissions reduction by 2030 below 2007 levels, and a reduction of 80% by 2050.

Federal: National targets cemented in the Net Zero Emissions Accountability Act stipulates do not impose binding provincial targets.

Electricity-sector decarbonization target: ✓

Provincial: The Clean Energy Act stipulates that 100% of the electricity generated and supplied to the grid must come from renewable sources by 2040.

Federal: The Clean Electricity Regulations stipulate net-zero electricity systems by 2050.

Policy instrument(s): ✓

Provincial: B.C.’s Output-based pricing system for large industrial operations, which was enacted through amendments to the Greenhouse Gas Industrial Reporting and Control Act (GGIRCA). The Renewable Energy Projects (Streamlined Permitting) Act aims to accelerate the approval of new renewable energy infrastructure.

Federal: The Clean Electricity Regulations require emissions reductions on electricity generated from fossil fuels starting in 2035. The Clean Technology ITC is a refundable tax credit of up to 30% capital invested in clean electricity generation, energy storage, low-carbon heating and certain zero-emission equipment.

Historical policy stability: medium

B.C.’s industrial pricing system has experienced substantive changes over the past 10 years, but key targets and policy instruments relevant for renewables investors stay in place.

B.C.’s current industrial pricing system from 2024 replaced the CleanBC Industrial Incentive Program which had been implemented in 2019. This change was in response to the 2023 review of the federal OBPS to ensure that B.C.’s system is aligned with the federal benchmarks.

Moreover, 2025 saw the rollback of a few broader decarbonization policies, including the consumer carbon tax, EV rebates, and net zero requirements (by 2030) for LNG projects. The roll-back of these policies may reduce demand for renewable electricity in the province, but without directly changing policy-driven incentives for wind and solar development.

QUEBEC

OVERALL SCORE: 4

Policy certainty “on the books”: high

Economy-wide decarbonization target: ✓

Provincial: The Environment Quality Act stipulates a 37.5% emissions reduction by 2035 (from 1990 levels); net zero emissions by 2050

Federal: National targets cemented in the Net Zero Emissions Accountability Act stipulates do not impose binding provincial targets.

Electricity-sector decarbonization target: ✓

Provincial: Quebec’s electricity supply is nearly completely decarbonized already. The Plan for a Green Economy stipulates that 80% of off-grid systems be supplied from renewable sources by 2030, but this target is not legally binding.

Federal: The Clean Electricity Regulations stipulate net-zero electricity systems by 2050.

Policy instrument(s): ✓

Provincial: QC’s cap and trade system has been in place since 2013 and was linked with the California market in 2014. The proceeds from credit auctions are invested in the Electrification and Climate Change Fund. No offset protocol for wind and solar projects. The system includes carbon border adjustments for imported electricity.

Federal: The Clean Electricity Regulations require emissions reductions on electricity generated from fossil fuels starting in 2035. The Clean Technology ITC is a refundable tax credit of up to 30% capital invested in clean electricity generation, energy storage, low-carbon heating and certain zero-emission equipment.

Historical policy stability: medium

QC has overall experienced policy stability over the past decade as its cap and trade system has expanded its coverage over time. Long announced reforms to QC’s system to address credit oversupply are expected in 2026.

A source of instability and uncertainty is that, in early 2026, the QC government postponed its 2030 emissions reduction target by 5 years to 2035, as it became clear that the province will not meet its 2030 target.

GERMANY

OVERALL SCORE: 5

Policy certainty "on the books": high

Economy-wide decarbonization target: ✓

National: The Federal Climate Change Action Act (Bundes-Klimaschutzgesetz) stipulates a 65% emissions reduction by 2030 (from 1990 levels) and a net-zero emissions economy by 2045.

Supra-national: The EU's target is to reduce emissions by at least 55% by 2030 below 1990 levels; net zero emissions by 2050

Electricity-sector decarbonization target: ✓

National: The Renewable Energies Act (Erneuerbare Energien Gesetz) requires at least 80% of Germany's gross electricity consumption to come from renewable sources by 2030. The Federal Climate Change Action Act sets technology-specific targets for offshore wind, solar PV, and onshore wind.

Supranational: The EU's Revised Renewable Energy Directive sets the target to increase the share of renewable energies in gross final energy consumption to at least 42.5% by 2030.

Policy instrument(s): ✓

National: The Renewable Energies Act (Erneuerbare Energien Gesetz) includes regulatory and financial incentives for renewable electricity generators, including grid feed-in priority and competitive auctions combined with subsidized tariffs.

Supra-national: The EU Emissions Trading Schemes (ETS) incentivizes investment in Germany's renewable electricity sectors by penalizing emissions and recycling ETS revenues to support expansions of renewables.

Historical policy stability: high

Over the past decade, Germany cemented climate targets in legislation, including the 2020 coal phase out legislation, the Building Energy Act. 2019, Federal Climate Change Action Act legislates emissions reduction targets. In 2021, Germany increased targets in response to a ruling by the German Federal Constitutional Court.

In September 2025, based on a "reality check" monitoring report on the energy transition, the government announced that while targets remain unchanged, demand projections for electricity are lower than previously expected, requiring less new wind and solar investment to meet targets and implying changes to current support mechanisms, including a phase out of support for some technologies. While this policy change may make Germany less attractive for new wind and solar projects, it avoids oversupply which may result in lower returns for existing projects. This can help build investor confidence in the long run.

U.K.

OVERALL SCORE: 5

Policy certainty “on the books”: high

Economy-wide decarbonization target: ✓

The Carbon Budget Order amendments to the Climate Change Act (2008) stipulate emissions reduction of 78% by 2035 (from 1990 levels) and net zero emissions by 2050.

Electricity-sector decarbonization target: ✓

To align with the national Carbon Budget 6, the goal is to meet total domestic demand from clean sources by 2030 and reduce the carbon intensity of electricity generation to below 50gCO2e/kWh; net zero electricity system by 2050

Policy instrument(s): ✓

National: UK Emissions Trading Scheme (U.K. ETS) launched in January 2021 after U.K.’s withdrawal from the EU ETS, covering power, industry and aviation sectors. The Carbon Price Floor covers the electricity sector in addition to the sector’s participation in the U.K. ETS. The Carbon Price Floor is set at a nominal rate of GBP 18.00 per tonne of CO2. U.K. Contracts for Difference, in force since 2014, guarantee a fixed price for electricity for clean electricity generators.

Supranational: In May 2025, the EU and the U.K. agreed to link their trading schemes; negotiations are on-going.

Historical policy stability: high

Based on the Climate Change Act and its carbon budget approach, the U.K.’s targets have been stable over the past decade, but specific policies and programs have changed. For example, feed-in-tariffs ceased in 2019, slowing investment in small scale wind and solar projects, and instead, auctions with contracts-for-difference became the key tool for supporting investment in renewables.

TEXAS

OVERALL SCORE: 2

Policy certainty “on the books”: low

Economy-wide decarbonization target: ✘

State-level: No explicit legislated target.

Federal: No explicit legislated target.

Electricity-sector decarbonization target: ✘

State-level: No explicit legislated target.

Federal: No explicit legislated target.

Policy instrument(s): ✘

State-level: None.

Federal: The Energy Policy Act from 2005 introduced 30 percent federal investment tax credits to utility-scale wind and solar projects; the Inflation Reduction Act from 2022 extended this credit to 2032. However, this tax credit will no longer apply to new projects coming online after 2027; as included in the One Big Beautiful Bill Act signed into law in July 2025.

Historical policy stability: medium

Despite not having had explicit targets in place over the past decade, Texas’ deregulated electricity market and free market ideology combined with great resources have led to record investment in wind and solar generation based purely on economic merit. The free market principles that are driving investment in Texas are unlikely to change, and the size and success of the state’s renewable electricity sector contribute to investment certainty going forward - even in the face of opposition to these sectors at the federal level.

In 1999, Texas introduced the first renewable portfolio standard in the U.S. and set legally binding targets for renewable energy production. To drive investment, Texas introduced a renewable energy credit trading program and established competitive renewable energy zones which helped connect large wind and solar generation projects with demand centres. Having surpassed all targets, the renewable portfolio standard was formally repealed in 2015, but by then the conditions were set for renewable energy to compete on economic merits alone.

The current federal government is actively opposing decarbonization and clean energy projects, introducing measures to slow permitting and cutting tax incentives. Also, import tariffs raise material costs for solar developers and weaken project economics. This policy instability at the federal level may affect investor confidence in renewables across the country, including in Texas.

WASHINGTON

OVERALL SCORE: 3

Policy certainty “on the books”: high

Economy-wide decarbonization target: ✓

State-level: The Climate Commitment Act sets in state law the goal to reduce emissions by 45% by 2030 (from 1990 levels), and to achieve net-zero emissions by 2050.

Federal: No legislated targets.

Electricity-sector decarbonization target: ✓

State-level: The Clean Energy Transformation Act (2019) stipulates that all electric utilities must be emissions neutral by 2030 and emissions-free by 2045.

Federal: No legislated targets.

Policy instrument(s): ✓

State-level: An economy-wide cap-and-investment system launched in 2023 and explicitly covers the power sector and large industrial emitters. In December 2025, an Executive Order aimed at accelerating the development of utility-scale solar and wind projects before federal tax credits run out.

The Energy Policy Act from 2005 introduced 30 percent federal investment tax credits to utility-scale wind and solar projects; the Inflation Reduction Act from 2022 extended this credit to 2032. However, this tax credit will no longer apply to new projects coming online after 2027; as included in the One Big Beautiful Bill Act signed into law in July 2025.

Historical policy stability: low

With considerable climate policy instability in the past, Washington’s carbon targets and carbon market have shown stability and resilience since key legislations came into force in 2019 and 2021. But this recent stability is overshadowed by instability at the federal level.

After a couple of failed attempts to introduce carbon pricing in the jurisdiction (in 2016 and 2017), the Clean Energy Transformation Act (CETA) became law in 2019 and the Climate Commitment Act (CCA) in 2021. The CCA was on the ballot again in 2024 but survived the challenge this time.

Washington is in the process of linking its carbon market with those of California and Quebec through the Western Climate Initiative.

The current federal government is actively opposing decarbonization and clean energy projects, introducing measures to slow permitting and cutting tax incentives. Also, import tariffs raise material costs for solar developers and weaken project economics. This policy instability at the federal level may affect investor confidence in renewables across the country, including in Washington.

NORWAY

OVERALL SCORE: 3

Policy certainty “on the books”: medium

Economy-wide decarbonization target: ✓

The Climate Change Act (Lov om klimamål (klimaloven) stipulates a 55% emissions reduction by 2030 (from 1990 levels), and a 90-95% reduction by 2050 (“low emission society”).

Electricity-sector decarbonization target: ✗

National: Norway’s electricity sector is 98 percent renewable; the government does not set specific targets for the power sector. A target for offshore development wind exists, but it is not legislated. The target is to develop an area for 30 GW of offshore wind production by 2040.

Policy instrument(s): ✓

National: Carbon tax (launched in 1991) on emissions from fuel combustion and other activities in the energy and industrial sectors.

Supranational: A European Free Trade Association country, Norway has participated in the EU Emissions Trading Scheme (ETS) since 2008. The EU ETS incentivizes investment in renewable electricity sectors by penalizing emissions and recycling ETS revenues to support expansions of renewables.

Historical policy stability: medium

Norway’s longstanding carbon tax and participation in the EU ETS provided stability over the past decade but local opposition to on-shore wind projects resulted in suspension of new licenses for multiple years.

Since the introduction of Norway’s carbon tax in 1991, the commitment to decarbonization has been overall stable. In 2018, the Climate Change Act introduced legally binding emissions reduction targets. The Climate Action Plan followed in 2021, and offshore wind targets in 2022. The targets were first introduced in 2022, and the first auction over 3GW capacity occurred in 2024, and more areas have been opened since. In 2024, Norway i increased its carbon tax (it is now one of the highest in Europe).

A break in policy stability was triggered by the widespread community opposition to rapid rollout of onshore windpower generation from 2017/18 onwards. Community resistance brought approvals of new projects to a halt from 2019 to 2022 and led to a reform of the licensing process to grant municipalities more control. Similarly, the future of Norway’s largest windfarm is uncertain after the country’s highest court revoked the project’s licence as it was found to violate the hunting rights of Indigenous Sami people.

NEW SOUTH WALES

OVERALL SCORE: 4

Policy certainty “on the books”: High

Economy-wide decarbonization target: ✓

State-level: The Climate Change (Net Zero Future) Act (2023) legislated the objective of reducing emissions by 50% by 2030 (from 2005 levels) and achieving net zero by 2050.

Federal: Australia’s federal policies: the National Climate Change Act (2022) stipulates a 43% emissions reduction by 2030 (from 2005 levels) and net zero by 2050.

Electricity-sector decarbonization target: ✓

Subnational: The Electricity Infrastructure Investment Act (2020) sets as infrastructure investment objectives the construction of at least 12 GWh of renewable generation capacity by 2030 and 28GWh of long-duration storage infrastructure by 2034. No legislated long-term targets.

National: No explicit legislated target.

Policy instrument(s): ✓

Subnational: Based on the electricity Infrastructure Investment Act (2020), NSW has declared 5 renewable energy zones across the state to facilitate the integration of wind and solar power by co-ordinating the construction of large renewable electricity projects. The Emerging Energy Program (total value $AUS 75 million) provides grants to large-scale electricity and storage projects.

National: Safeguard Mechanism is an emissions trading system covering large emitters in mining, manufacturing, transport, oil, gas and waste sectors. It was implemented in 2023.

Trade of large-scale generation certificates, where electricity retailers must buy and submit a certain number of credits from generators to meet obligations under the Renewable Energy (Electricity) Act 2000.

Australia’s Capacity Investment Scheme is a competitive tender program that offers investors in renewable generation and storage long-term, revenue-underwriting agreements to mobilize investment and contribute to the nation’s climate goals. The target is to add 26GW of renewable generation capacity and 14GW of dispatchable capacity by 2030.

Historical policy stability: medium

While NSW’s clean renewable electricity policy has been stable recently, key legislations and programs only have a short track record.

Up until the late 2010s, NSW pursued a hands-off approach to electricity policy, relying upon market forces to drive investment in renewables. But policy uncertainty at the federal level slowed investment, and NSW’s government adopted a more interventionist approach to mobilize investment in renewables. Key pieces of legislation cementing this new path were passed, the Electricity Infrastructure Investment Act in 2020, and the Climate Change (Net Zero Future) Act in 2023.

At the federal level, key programs are similarly young. The first tradeable permits under Australia’s federal carbon trading scheme were issued in February 2025. And the first competitive tender under the Capacity Investment Scheme occurred in 2023—although the program was expanded in 2025, raising the 2030 target capacity additions from 32GW to 40GW.

Limitations:

This metric focuses on policy certainty, it does not consider and compare the levels of targets and stringency of policy incentives. Stringency (e.g., the level of a jurisdiction's effective carbon price) matters for clean electricity investors in addition to policy certainty. This metric also does not consider whether implemented policy instruments are setting sufficiently strong investment incentives to achieve the defined decarbonization targets.

More generally, this approach to assessing a jurisdiction's climate policy certainty is inevitably reductionist in nature. In reality, many other factors not considered in this methodology can influence investors' perception of climate policy certainty in a given jurisdiction. A more accurate assessment could be based on surveying investors about their perceptions of policy certainty in different jurisdictions.

Moreover, the two indicators, policy certainty "on the books" and historical policy stability are both backward looking in nature, because a jurisdiction's score only changes after a government has changed targets and/or instruments. That is why the MOU implementation agreement between the Alberta government and the federal government does not immediately affect the policy certainty scores of other Canadian provinces although it makes future policy changes more likely. A more complete measure of certainty would be forward-looking, e.g. by estimating the likelihood of policy changes in the future based on certain indicators.

Finally, to determine a jurisdiction's overall level of climate policy certainty, we assigned equal weights to policy certainty "on-the-books" on one hand and historical policy stability on the other. We chose the equal weighing largely for simplicity, recognizing that different investors may weigh these elements differently in their assessments of a jurisdiction's climate policy certainty.