Alberta ENERGY EFFICIENCY ALLIANCE

Demand Response Primer

JUNE 2026

This primer is a compilation of research undertaken by the Alberta Energy Efficiency Alliance (AEEA) and is informed by the AEEA's engagement of stakeholders in the province, which include distribution utilities and demand response aggregators.

Funding for this research has been provided by Alberta Ecotrust, Alberta Innovates, the Alberta Real Estate Foundation, Natural Resources Canada and Prairies Economic Development Canada.

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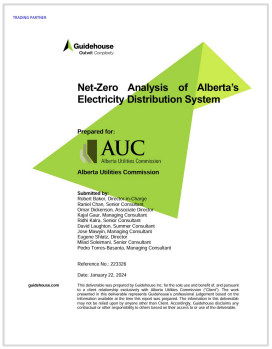
Background

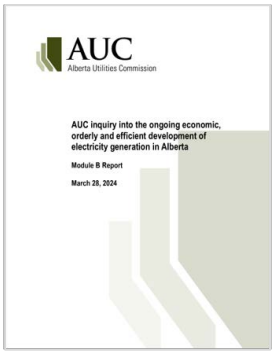
Defining Demand Response

Demand response (DR) programs involve consumers responding to a signal to reduce electricity use during times of high consumption.[1] The signal is typically generated by electric utilities or system operators as a way to manage peak electricity demand and reduce the need for additional supply-side infrastructure like distribution, transmission and generation assets. Increasing DR programs in a jurisdiction is a common strategy for reducing system-wide costs and increasing system-wide reliability.

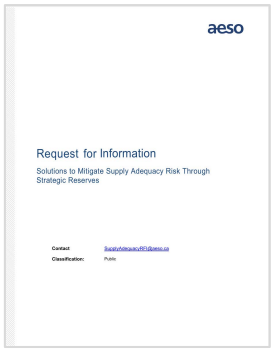


Past Interest in Demand Response

Interest in increasing the use of DR in Alberta's electricity system has been demonstrated in several ways:



- *Net Zero Analysis of Alberta's Electricity Distribution System*[2]
    - Included DR as an opportunity to mitigate future electricity system costs, prepared for the Alberta Utilities Commission (AUC) by Guidehouse.
- *AUC inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta – Module B Report*[3]
    - Listed DR as an opportunity to reduce future costs to electricity consumers.
- The Alberta Electric System Operator (AESO) listed DR as a topic of interest within their engagement on Strategic Reserves.[4]
- Distribution utilities in the province have indicated their interest in DR and other approaches to demand side management (DSM) as outlined in their comments responding to the AUC's recent *Time Varying Rates* report.[5]



[1] The same effect can be accomplished through dispatchable behind-the-meter battery storage and distributed generation, which can also be included as DR resources.

[2] Alberta Utilities Commission. 2024. Net-zero analysis of Alberta's electricity distribution system. Retrieved from https://www.auc.ab.ca/net-zero-analysis-of-albertas-electricity-distribution-system/.

[3] Alberta Utilities Commission. 2024. *AUC inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta: Module B Report*. Retrieved from https://media.auc.ab.ca/prd-wp-uploads/regulatory_documents/Reference/28542_Inquiry-ModuleB-Report.pdf.

[4] Alberta Electric System Operator. 2025. *Strategic Reserves*. Retrieved from https://aesoengage.aeso.ca/strategic-reserves.

[5] Alberta Utilities Commission. 2025. Engagement on enabling time-varying rates and other demand-side opportunities for residential and other electricity customers in Alberta. Retrieved from https://engage.auc.ab.ca/consultations/engagement-on-enabling-time-varying-rates-for-residential-and-other-electricity-customers-in-alberta/.

- DR also provides a ready-made response to the Premier of Alberta's recent mandate letter to the Minister of Affordability and Utilities, which includes a commitment to, "Work with industry on providing the government with proposals to assist with more efficient electricity usage through demand-side management".[6]

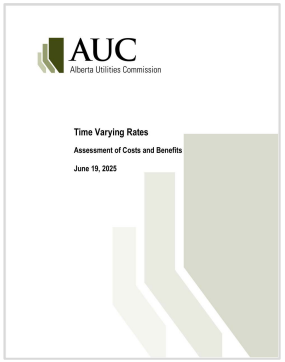
- For the first time, non-wires services was added to Alberta's *Electric Utilities Act* and *Hydro and Electric Energy Act* following the proclamation of the *Electricity Statutes Amendment Act, 2022* (formerlly Bill 22).[7]

    - While these acts did not specifically define non-wires services, they do reference the direct procurement of these resources by owners of electric distribution systems, and specify: "The owner of an electric distribution system has the following duties: […] (b) to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy having regard to […] any non-wires services".

- Non-wires solutions were also recognized as a requirement for distribution utilities to consider when filing for Type 1 capital projects under their 2024-2028 Performance Based Regulation (PBR) framework.[8]

    - There are limitations, however, in how Alberta distributors can effectively use non-wire solutions at this time. This will be further addressed in the Recommendations for Alberta section below.

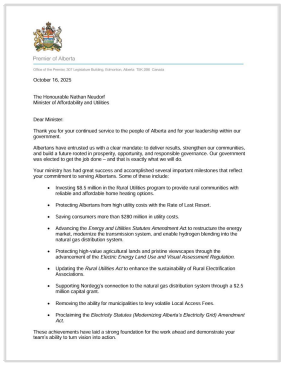
This DR Primer has, therefore, been developed to contribute to ongoing discussions by these groups and other stakeholders in the province relating to the role DR can play in Alberta's electricity system and steps that can be taken to increase its use for the benefit of Alberta consumers.


AUC
Alberta Utilities Commission

Time Varying Rates

Assessment of Costs and Benefits

June 19, 2025


Premier of Alberta

October 16, 2025

The Honourable Nathan Neudorf
Minister of Affordability and Utilities

Dear Minister:

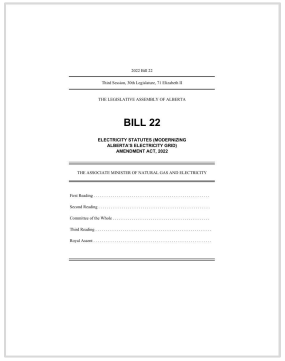
Thank you for your continued service to the people of Alberta and for your leadership within our government.

Albertans have entrusted us with a clear mandate: to deliver results, strengthen our communities, and build a future rooted in prosperity, opportunity, and responsible governance. Our government was elected to get the job done — and that is exactly what we will do.

Your ministry has had great success and accomplished several important milestones that reflect your commitment to serving Albertans. Some of these include:

- Investing $8.5 million in the Rural Utilities program to provide rural communities with reliable and affordable home heating options.
- Protecting Albertans from high utility costs with the Rate of Last Resort.
- Saving consumers more than $280 million in utility costs.
- Advancing the *Energy and Utilities Statutes Amendment Act* to restructure the energy market, modernize the transmission system, and enable hydrogen blending into the natural gas distribution system.
- Protecting high-value agricultural lands and pristine viewscapes through the advancement of the *Electric Energy Land Use and Visual Assessment Regulation*.
- Updating the *Rural Utilities Act* to enhance the sustainability of Rural Electrification Associations.
- Supporting Nurelogy's connection to the natural gas distribution system through a $2.5 million capital grant.
- Removing the ability for municipalities to levy volatile Local Access Fees.
- Proclaiming the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*.

These achievements have laid a strong foundation for the work ahead and demonstrate your team's ability to turn vision into action.


2022 Bill 22

Third Session, 30th Legislature, 71 Elizabeth II

THE LEGISLATIVE ASSEMBLY OF ALBERTA

BILL 22

ELECTRICITY STATUTES (MODERNIZING ALBERTA'S ELECTRICITY GRID) AMENDMENT ACT, 2022

THE ASSOCIATE MINISTER OF NATURAL GAS AND ELECTRICITY

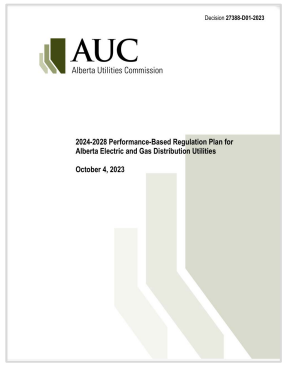
First Reading .....

Second Reading .....

Committee of the Whole .....

Third Reading .....

Royal Assent .....


Decision 27388-D01-2023

AUC
Alberta Utilities Commission

2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities

October 4, 2023

Defining Demand Side Management and Demand Flexibility

Demand response is often discussed within the context of several overarching terms such as demand side management and demand flexibility. The following definitions describe how these terms relate to one another as they are used within this primer.

[6] Premier of Alberta. 2025. Affordability and Utilities Mandate Letter. Retrieved from https://open.alberta.ca/dataset/b0769b96-7a45-40b5-b57c-415ff82aca49/resource/ca616716-cdfc-4627-b109-66222530d27d/download/au-mandate-letter-affordability-and-utilities-2025.pdf.

[7] Legislative Assembly of Alberta. 2022. *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022*. Retrieved from https://docs.assembly.ab.ca/LADDAR_files/docs/bills/bill/legislature_30/session_3/20220222_bill-022.pdf

[8] Alberta Utilities Commission. 2023. *2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities*. Retrieved from https://ucahelps.alberta.ca/media/uxahtbes/decision-27388.pdf.

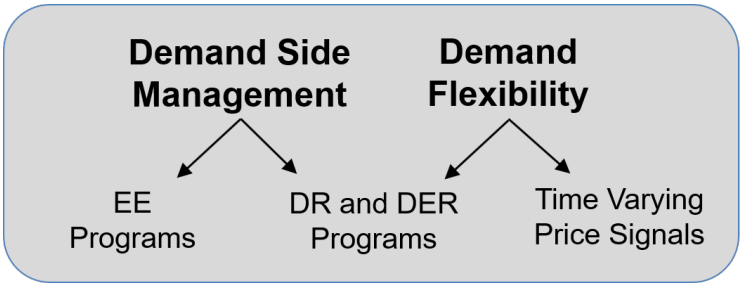
Demand Side Management – an umbrella term that often includes a range of consumer-facing programs that provide support for:

- energy efficiency upgrades in buildings and industrial facilities,
- increasing use of behind-the-meter (BTM) distributed energy resources (DERs) like distributed generation and battery storage, and
- decreasing electricity use during peak times through demand response programs.

Demand Flexibility – another umbrella term that incorporates a range of approaches to increasing the flexibility of electricity consumption and/or export to the grid by BTM distributed generation or battery storage. Examples include:

- Demand response and DER programs
- Time varying price signals provided through:
  - Wholesale market prices
  - Procurement of ancillary services such as operating or regulating reserves
  - Time varying rates (TVR)
  - Rates for interruptible or curtailable loads

It should be noted that while DSM programs are often treated as separate from time-varying price signals, they can serve similar goals and are sometimes bundled together within a broader suite of tools to engage consumers to affect how and when they use electricity.



How do Virtual Power Plants (VPPs) fit in?

VPP is a relatively new term and is currently being used in a variety of ways. The broadest definition of a VPP is an aggregation of many, small, distributed energy resources. VPP definitions have included aggregation of distributed generation, batteries, electric vehicle chargers, smart thermostats and even electric water heaters. Within these definitions, VPPs can export power to the grid, reduce their demand on the grid and/or draw power from the grid. VPPs have been known to participate in DR programs, ancillary services, wholesale markets, as price responsive loads, and as non-wire solutions. Given the potential for broad application of the VPP term to a number of the topics addressed in this paper, it has not been generally used to avoid potential confusion between the different ways the VPP term has been used to date.

Previous research into different approaches to DSM and increasing demand flexibility in jurisdictions with similar market characteristics as Alberta (including a competitive wholesale market) concluded that they all use a suite of approaches side-by-side in order to affect how and when consumers use electricity (highlighted in blue in the table below).

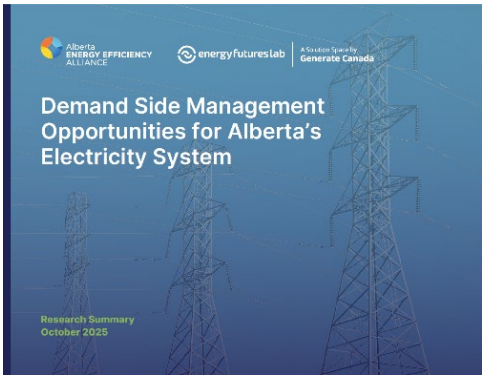
Mechanism for Engaging Demand	Texas	California	New York	Australia	United Kingdom	Ontario
Direct participation by large loads in ancillary services and/ or wholesale markets	Currently enabled	Currently enabled	Currently enabled	Currently enabled	Currently enabled	Currently enabled
Aggregation of small or medium-sized loads for participation in ancillary services and/ or wholesale markets	Currently enabled through aggregator specific rules	Currently enabled through aggregator specific rules	Aggregator specific rules for DERs >10 kW (also receives bill credit from distribution utilities)	Currently enabled through aggregator specific rules	Currently enabled through aggregator specific rules	DR aggregation in capacity auction
Time variable rates on electricity consumption	Currently offered as an optional rate	In place for most customers, still optional for some residential customers	Currently offered as an optional rate	Currently offered as an optional rate	Currently offered as optional rates (static and dynamic)	Currently the default rate with ability for customers to opt-out
Coincident peak pricing on transmission rates for large loads or **time related demand charges**	Four Coincident Peak (4CP) T&D demand charges for large industrial and commercial	Time variable demand charges for non-residential + optional critical peak pricing during summer	No time-related demand charges for wires found	Some demand tariffs based on peak periods only	Time variable demand charges for larger customers	Global Adjustment for large customers based on 5 peak hours (offers DR program to mitigate cost)
Demand response programs by wires utilities or retailers	In place for T&D utilities	In place for T&D utilities	In place for distribution utilities	Distribution networks required to have demand side engagement strategies + energy retailer targets in place in most states (can self-fulfill and/ or buy certificates)	Local flexibility procurement by distribution system operators	IESO delivers Conservation and Demand Management Programs (including residential DR) + Local Demand Response by Toronto Hydro
Energy efficiency programs by wires utilities or retailers	In place for T&D utilities (gas utilities as well)	In place for T&D utilities (includes natural gas)	In place for distribution utilities (includes natural gas) + NYSERDA		Obligations for medium and large energy retailers to support low income households	

While the focus of this Primer is on DR programs, more details on the other overlapping approaches for demand side engagement can be found in *Demand Side Management Opportunities for Alberta's Electricity System*[9].

Benefits of Demand Response

The same report also outlined a number of benefits of DR, and DSM more broadly:

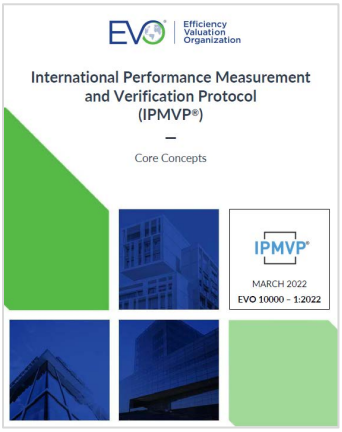
- Improves the **affordability** and **reliability** of electricity supply by helping consumers be more efficient and flexible in how and when they use electricity
- Helps **optimize** use of existing infrastructure (including generation, transmission and distribution) by reducing peak demand and grid



[9] Alberta Energy Efficiency Alliance and Energy Futures Lab. 2025. Demand Side Management Opportunities for Alberta's Electricity System. Retrieved from https://www.aeea.ca/wp-content/uploads/2025/11/DSM-Opportunities-for-Albertas-Electricity-System-Oct-2025.pdf.

pressure, and in some cases deferring the need for higher-cost investments

- Increases **consumer satisfaction** by improving customer choice in how they manage their bills and leverage on-site devices
- Generates opportunities for **local businesses** and **trades**
- Cost-effectively **reduces emissions** and complements other emission reduction efforts
- Enhances Alberta's **economic competitiveness** by lowering the cost-of-living and cost-of-doing-business in the province



It should be noted that DR and DSM are both scalable resources that can leverage both small and large consumers. It is also universal for the electricity system benefits of DR and DSM programs to be regularly measured and verified by third parties using internationally recognized protocols, such as the International Performance Measurement and Verification Protocol[10] (IPMVP), prior to being submitted to and reviewed by utility regulators as part of standard governance and oversight procedures of DR and DSM programs.

What are DR programs?

Uses of DR Programs

DR programs are used for a variety of purposes including, but not limited to:

- Reducing load during **emergency events** on the bulk electricity system or local distribution grids
- As a **non-wire alternative (NWA)** by delaying or deferring the need for infrastructure investment within both the distribution and transmission portions of the system
- As a way to mitigate system-wide electricity costs by **increasing responsiveness to high prices**
- As an **ancillary service** to manage system reliability – for example, as an operating or regulating reserve

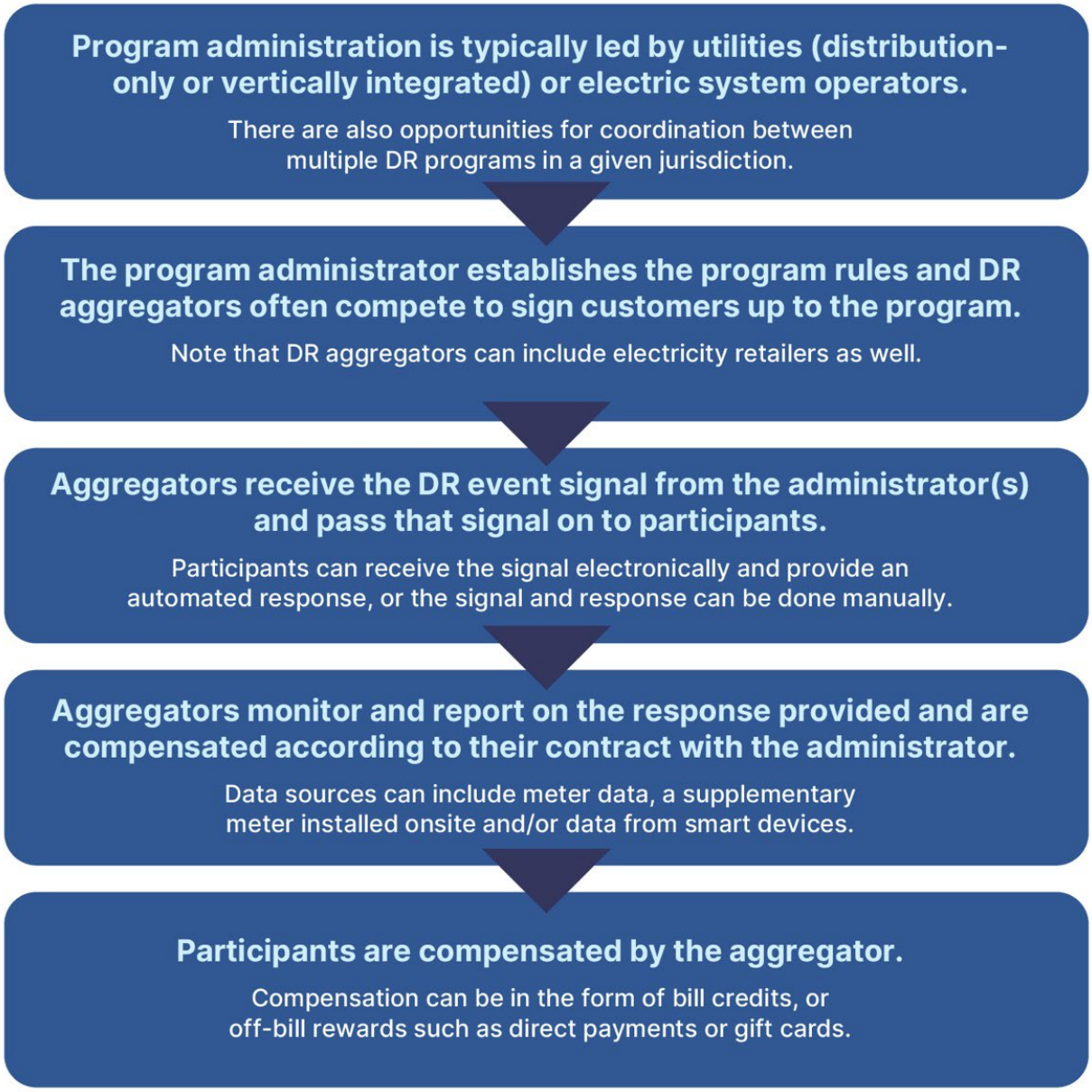
In some cases, DR programs are used for multiple purposes and they can even be designed for general peak load management, which supports all of the purposes listed above without an explicit focus on any one purpose.[11]

[10] Efficiency Valuation Organization. 2022. *International Performance Measurement and Verification Protocol (IPMVP)*. Retrieved from https://evo-world.org/en/products-services-mainmenu-en/protocols/ipmvp.

[11] For example, the Commercial System Relief Program (CSRP) in New York is triggered based on day-ahead peak demand forecasts or forecasted temperatures allowing the program to contribute to several uses, while not being limited to any one specific use. See section 1: Program Summaries at https://cdnc-dcxprod2-sitecore.azureedge.net/-/media/files/coned/documents/save-energy-money/rebates-incentives-tax-credits/smart-usage-rewards/smart-usage-program-guidelines.pdf

Structure of DR Programs

There are a large number of DR programs across Canada and internationally.[12] While there are unique elements to most program designs, they generally follow a similar basic structure.



[12] Efficiency Canada. 2025. *A preliminary look at demand flexibility and peak demand reductions in Canada*. Retrieved from https://www.efficiencycanada.org/a-preliminary-look-at-demand-flexibility-and-peak-demand-reductions-in-canada/.

Approaches to DR Procurement

Note that a variety of approaches can be used by program administrators to procure DR resources. This can include:

- Standard offer programs: Aggregators and consumers sign up for programs with pre-defined compensation levels and program requirements. (E.g., Distribution-level load management programs in Texas)
- Requests for proposals (RFP): Aggregators and/or large consumers propose the level of compensation for delivering the load reduction targeted by the program administrator, and the administrator awards contracts to one or more DR resources based on the competitive RFP process. (E.g., non-wire alternative procurement by National Grid in New York state for both distribution and transmission system upgrades[13])
- Auctions: Offers are provided by aggregators and/or directly from large consumers to be available to reduce their load over a given timeframe (often a full summer or winter season). Often in competition with other resource types, such as generation, the lowest cost offers that meet the procurement target are then awarded contracts to fulfill their obligations during DR events. (E.g., electricity capacity market auctions in PJM, MISO and ISO New England[14])
- Short-term electricity markets: Day-ahead and/or intraday electricity markets function similar to auctions, but operate in a much shorter timeframe. (E.g., Operating Reserves in Alberta).

It should also be noted that more than one procurement approach can be used for a given DR program. For example, a program administrator could use an openly competitive RFP to select a program implementation contractor who is then responsible for delivering a standard offer program involving open competition among aggregators to sign customers up who are then compensated using a standard offer. Jurisdictions can also use a combination of program types in parallel with one another to meet multiple system needs. For example, DR procurement in New York state includes standard offer programs for distribution connected consumers, NWA RFPs, and DR procurement as capacity resources operating in parallel with one another with distribution and transmission utilities involved in each.

DR Procurement Levels

The level of DR procurement targeted by a given program can be set in several ways.

- Procurement levels for geographically broad DR programs (such as general peak load management or emergency response programs) are often established using benefit-cost analysis to ensure the programs are cost-effective and provide a suitable return on investment (ROI) to ratepayers. The procurement level is approved by utility regulators prior to program approval.
- Procurement levels for non-wire solutions (which can include demand response, energy efficiency and other DERs) are typically established through a benefit-cost analysis comparing the cost of the solution to the savings associated with delaying or deferring new upstream investments. The procurement level is also approved by utility regulators prior to approval of NWS implementation.

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[13] National Grid. 2026. *Non-Wires Alternatives*. Retrieved from https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/.

[14] Includes participation by utility administered DR programs.

- For ancillary services (such as operating reserves), the procurement levels are set by system operators or utilities to meet established reliability standards. Procurement levels can also be set by these groups, or government, to meet other objectives such as increasing the total number of DERs in a jurisdiction.
- For procurement through electricity capacity markets, the amount of DR procured is based on the demand for capacity in a given auction, and the price of offers submitted by utility DR programs, third-party DR aggregators and competing capacity resources (i.e., generation and storage).

Benefit-Cost Analysis

Where benefit-cost analysis is used to inform DR procurement, it is a standard practice for program administrators to use a pre-defined cost effectiveness test, and for utility regulators to review the cost effectiveness of programs both before they are approved and after they have been undertaken (using third party verified data).

The costs of DR programs generally fall into 3 main categories:

1) the cost of procuring DR from aggregators[15] and participants[16],
2) the cost of program administration (including the cost of program evaluation), and
3) a utility earnings mechanism.

The benefits included in cost effectiveness tests for DR programs can include some or all of the following factors:

- Avoided wires costs (broadly within the system due to reduced system strain and/or specifically within a targeted non-wire solution),
- Avoided transmission and distribution (T&D) line losses,
- Avoided ancillary services costs, and
- Reduced energy market costs (similar to the benefits outlined in the AUC's *Time Varying Rates* report[17]).

The following table outlines avoided costs used in benefit-cost analyses in jurisdictions reviewed.[18]

[15] Including the cost of aggregation software platforms and any involvement of Original Equipment Manufacturers (OEMs)

[16] Note that the cost of participant incentives is not included in all cost effectiveness tests, particularly those from the consumer perspective, as it is also a direct benefit to consumers.

[17] Alberta Utilities Commission. 2025. *Time Varying Rates – Assessment of Costs and Benefits*. Retrieved from https://media.auc.ab.ca/prd-consultation/sites/2/2025/06/2025-06-19-FINAL-TVR-REPORT.pdf.

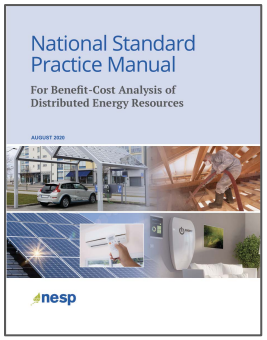
[18] American Council for an Energy Efficient Economy (ACEEE). 2026. *Database of State Efficiency Screening Practices (DSP).* Retrieved from https://www.aceee.org/database-state-efficiency-screening-practices.

Independent Electric System Operator (IESO). 2022. *Cost Effectiveness Guide for Energy Efficiency*. Retrieved from https://www.ieso.ca/-/media/Files/IESO/Document-Library/EMV/IESO-CDM-CE-TestGuide-V9.ashx.

Ontario Energy Board (OEB). 2024. *Benefit-Cost Analysis Framework for Addressing Electricity System Needs*. Retrieved from https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-05/OEB_BCA_Framework_FINAL-AODA.pdf.

Benefit included in cost effectiveness tests	Ontario	Texas	California	New York
Avoided marginal cost of energy	✓	✓	✓	✓
Avoided generating capacity cost	✓	✓	✓	✓
Avoided T&D	✓		✓	✓
Avoided line losses		✓	✓	✓
Avoided ancillary services			✓	✓
Avoided environmental compliance costs			✓	✓
Avoided credit and collection costs				✓
Increased resilience				✓

More information on common methodologies for calculating program costs and benefits can be found in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*[19]. Note that the definition of distributed energy resources (DERs) in this manual is inclusive of a broad range of resources including DR, energy efficiency, distributed generation and distributed storage.



How do DR programs compare with Time Varying Rates?

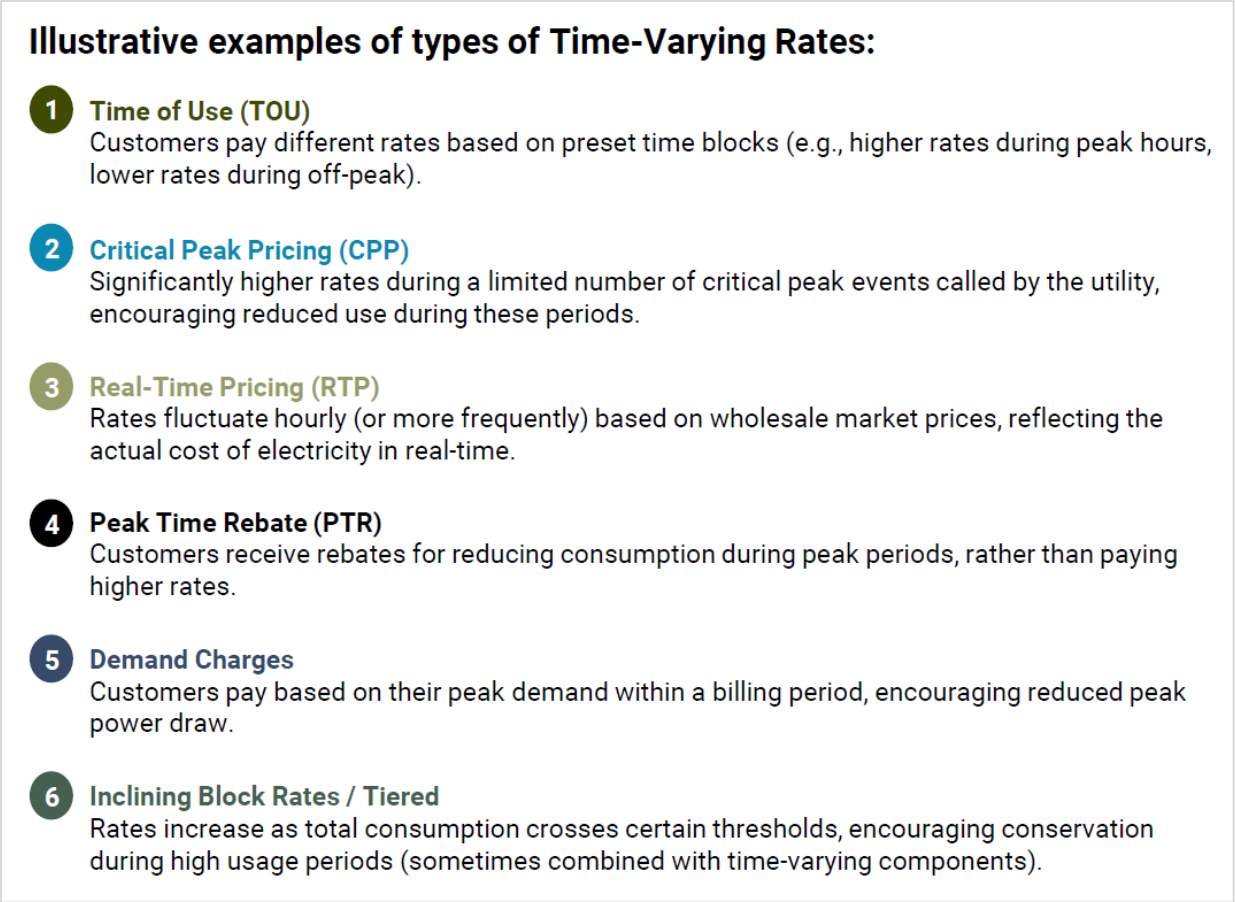
Both DR programs and time varying rates (TVR) have the ability to influence when consumers use electricity, increasing demand flexibility and providing another tool for balancing supply and demand on the grid, and reducing peak loads. These demand flexibility tools may appear as options to choose from, but research into other jurisdictions shows that it is common for TVR and DR programs to co-exist and provide compatible approaches to influencing consumer demand.[20]

[19] National Energy Screening Project. 2020. National Standard Practice Manual. Retrieved from https://naseo.org/Data/Sites/1/media/tknaseo/nspm-ders_08-24-2020.pdf.

[20] Alberta Energy Efficiency Alliance and Energy Futures Lab. 2025. Demand Side Management Opportunities for Alberta's Electricity System. Retrieved from https://www.aeea.ca/wp-content/uploads/2025/11/DSM-Opportunities-for-Albertas-Electricity-System-Oct-2025.pdf.

What are Time Varying Rates?

TVR is a tool that can provide a price signal to consumers to influence when they use electricity. There are many different approaches to TVR as recently described by the Alberta Utilities Commission[21].



Each of these approaches provides different response characteristics and varied consumer sentiment depending on how they are implemented. For example, research by the Alberta Smart Grid Consortium demonstrated relatively low favourability towards TOU pricing with only 37% of commercial respondents, 46% of farm respondents and 51% of residential respondents favouring TOU over current rates. Favourability is expected to be even lower for rates with higher variability and lower predictability (such as CPP and RTP). PTR, on the other hand, only provides bill rebates for reducing consumption during peak periods (similar to DR programs) and is expected to be more favourably viewed by customers.[22] The favourability of TVR is also expected to vary considerably based on whether it is mandatory, voluntary or a default rate.

It should be noted that TVR can be applied to the energy and/or wires portion of electricity bills. Care should be taken, however, when applying TVR to wires charges as recently reflected by the AUC when commenting on the use

[21] Alberta Utilities Commission. 2025. TVR & Other DSM Enablement, Introductions & Engagement Overview –October 20, 2025. Slide 21.

[22] See page 14 of: Time-Varying Rates are Moving from the Periphery to the Mainstream of Electricity Pricing for Residential Customers in the United States.

of coincident peak pricing for transmission charges. In their November 2022 decision related to the AESO Rate Design Application, the AUC indicated the AESO should not use readily avoidable billing determinants (i.e., coincident peak pricing) for the purpose of recovering sunk costs.[23] This can result in burden shifting from more affluent consumers, with a greater ability to invest into new technologies, to consumers on low or fixed incomes.

Current state of TVR in Alberta

In Alberta, most industrial and large commercial consumers (approximately 75% of load in the province) are already exposed to some form of TVR through their demand and/or consumption charges. Due to this exposure, many large industrial consumers actively manage their electricity costs through a combination of approaches including hedging their price exposure by generating their own electricity, varying their electricity consumption over time, and offering their demand flexibility as ancillary services. Smaller industrial and commercial consumers are not as noticeably active in managing their electricity costs in these ways and it is currently unclear how responsive these loads are to time varying price signals they may be exposed to. It is expected that many small and medium-sized consumers prefer to manage potential cost volatility by purchasing most, if not all, of their electricity through retailers at fixed rates.

More recently, there is an emerging example of at least one electricity retailer[24] offering market prices (RTP) to residential customers with BTM solar and batteries that opt-in to interval metering as opposed to the monthly cumulative metering currently in place for most residential and small commercial customers in the province. While the uptake for market rates by small consumers is currently limited, this example shows there is already some potential for expanded offerings of voluntary TVR in the province in the near term.

For broad implementation of TVR (e.g., as a default energy rate), it is expected that market settlement will need to move from monthly settlement to sub-hourly intervals – requiring upgrades to both metering and meter data management infrastructure. Based on communications from the Minister of Affordability and Utilities to the AESO, shorter settlement for all consumers is currently targeted for no later than 2040 given the time required for all meters in the province to be able to read at 5-minute intervals.[25]

DR vs. TVR

As with TVR, DR programs also send a price signal to consumers to vary their electricity consumption, but the signal can occur based only on emergency events, on a daily basis to avoid times of peak demand or some frequency in between depending on the objectives and design of the DR program. DR programs also have the ability to enable somewhat different response characteristics than TVR. For example:

- DR programs provide a higher certainty of response than consumer responses to TVR due to the contract nature of DR programs. DR programs can also require the use of direct load control (DLC) so the program administrator or aggregator can directly control the distributed energy resource (e.g., smart thermostat,

[23] Alberta Utilities Commission Decision 26911-D01-2022, page 16, paragraph 76.

[24] Solartility Energy Inc. 2025. Company website. https://solartility.ca/

[25] Alberta Affordability and Utilities. 2024. Director Letter to the Alberta Electric System Operator. December 10, 2024. Retrieved from https://www.aeso.ca/assets/direction-letters/Direction-Ltr-from-Minister-REM_Tx-Policy_10Dec2024.pdf.

behind-the-meter battery, hot water heater or smart EV charger), which increases the certainty of responsiveness and can avoid negative impacts such as shadow peaks.[26]

- DR programs run by distribution utilities are also better suited to help address local distribution system needs as well as bulk or province-wide system needs whereas TVR is usually based on system-wide electricity market prices only, which does not always match local system needs.
- DR programs can be implemented prior to fully enabling advanced metering infrastructure (AMI) whereas TVR requires AMI / interval meters to be in place.[27]
- DR programs are positively received by consumers given their incentive nature and can be an early entry point for consumers to becoming flexible loads before TVR is introduced (which is viewed as more of a 'stick' approach to behaviour change).

It should be noted that one advantage of TVR over DR programs is that TVR can ultimately be made mandatory or as a default rate for all consumers whereas DR programs are always voluntary. Care should be taken, however, when implementing mandatory or default TVR as there is a significant chance of pushback by consumers given relatively low favourability mentioned above. Ontario, for example, shifted from mandatory TOU to TOU as a default rate in order to provide consumers with an alternative approach to managing their electricity costs.

One advantage of DR programs over TVR that should be noted is the scale of the price signal possible through each. For example, compensation for load flexibility during emergency events can be set relatively high through DR programs to reflect the high value of demand reductions during extreme events. TVR on the other hand, is typically delivered through TOU rates for most consumers that provide the same price signal across an entire season or year regardless of grid conditions on any given day. More extreme TVR prices are generally poorly received by consumers due to the significantly increased risk of much higher bills during critical peaks and emergency events.

Given the relative advantages and disadvantages of both TVR and DR programs, it is important to consider how they can work together to incent both daily load shifting through TVR and larger, event-specific load shifting through DR programs. This approach is taken in jurisdictions with comparable market structures to Alberta and has ultimately resulted in a multi-pronged strategy to increasing demand flexibility in a jurisdiction.[28]

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[26] Shadow peaks from equipment ramp up at the end of TOU periods is an issue highlighted by a recent smart charging EV project led by FortisAlberta. See Electric Vehicles and the Energy Transition: Unintended Consequences of a Common Retail Rate Design for more information.

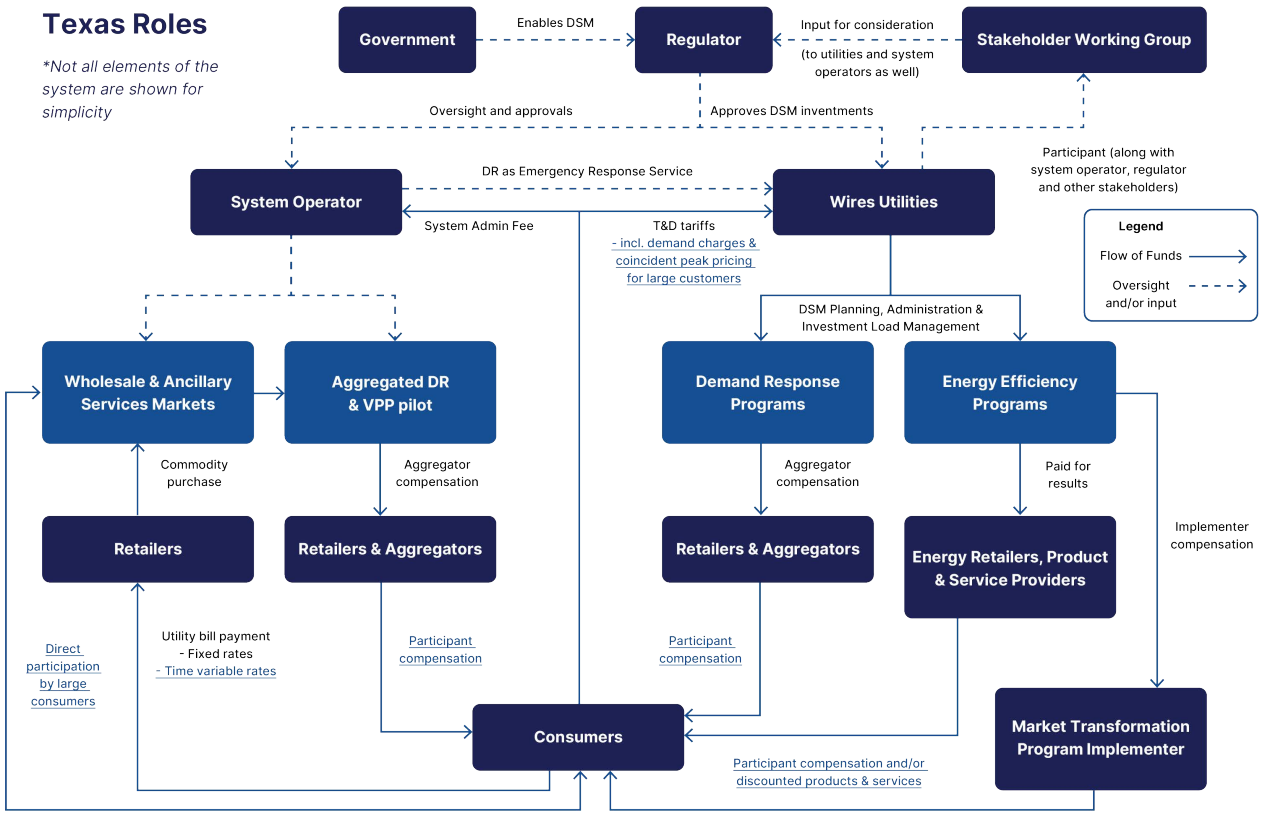
[27] For example, many residential programs use device telemetry data obtained from internet-connected equipment (e.g., smart thermostats, EV chargers and/or battery energy storage systems) as their primary data sources to verify performance.

[28] Alberta Energy Efficiency Alliance and Energy Futures Lab. 2025. *Demand Side Management Opportunities for Alberta's Electricity System*. Retrieved from https://www.aeea.ca/wp-content/uploads/2025/11/DSM-Opportunities-for-Albertas-Electricity-System-Oct-2025.pdf.

Structuring DR programs

Given its similar market structure, Texas provides a useful example for how DR programs could be approached in Alberta. The image below provides a rough outline of several approaches to engaging consumers with respect to how and when they use electricity in the state.

Approaches to demand side engagement in Texas



Note: Blue underlines show the various mechanisms in place to engage consumers, and influence how and when they use their electricity.

The *2025 Annual Report on Demand Response in the ERCOT Region*[29], lists five different categories of DR products in the region along with the equivalent existing approach in Alberta where applicable. It should be noted that there are multiple products in some of the categories listed for Texas.

[29] Electric Reliability Council of Texas (ERCOT). 2026. *Annual Report on ERCOT Demand Response*. https://www.ercot.com/mp/data-products/data-product-details?id=NP3-110

Texas DR Product Categories	Alberta Equivalent
Load participation in ERCOT ancillary services	Load participation in AESO ancillary services
Aggregate Distributed Energy Resources (ADER) Pilot Project	Aggregated distributed energy resources (e.g., distributed generation and/or battery storage) participation in AESO ancillary services and wholesale market
4-Coincident Peak (4-CP) pricing of transmission charges and price-responsive DR	12-Coincident Peak Demand (12-CP) pricing of transmission costs for transmission connected customers and price-responsive large loads
Emergency Response Service (ERS)	None
Transmission / Distribution Service Provider (TDSP) Load Management Programs	None

The above table shows Alberta already has DR opportunities in 3 of the 5 DR product categories currently active in Texas. Adding emergency response service at the system operator level and load management programs at the distributor level would help to fill gaps relative to not only Texas, but other comparable jurisdictions.[30]

It should be noted that in Texas, load management programs run by wires utilities serve to address both local peak load management and can be used as an emergency response service for ERCOT. Given this dual benefit of local DR programs, and the opportunity they provide to increasing DR opportunities for a broad range of industrial, commercial and residential consumers, the rest of this primer focuses DR opportunities at the distribution level.

This isn't to say that there aren't opportunities to increase DR for large, transmission-connected loads as these are currently the largest flexible loads in the province. Consideration should also be given to how a combination of wholesale market prices, coincident peak demand pricing on transmission rates and the potential addition of emergency response services by the AESO could help to maximize the flexibility benefits possible from transmission connected loads in the province.

Distribution level DR programs

There are a range of approaches that can be taken for distribution level DR programs. This section outlines several of those approaches as well as a recommendation for where to start in Alberta.

Uses of distribution level DR programs

When reviewing DR programs at the distribution level in other jurisdictions, there are two primary ways of approaching these programs:

[30] More details on approaches to DR in other jurisdictions can be found at https://www.aeea.ca/wp-content/uploads/2025/11/DSM-Opportunities-for-Albertas-Electricity-System-Oct-2025.pdf

- General peak load management
    - Examples include DR programs run by distribution utilities in Texas, California and New York. The benefits targeted by these programs include avoided marginal costs of generation (calculated based on the costs of a new electricity peaking plant), avoided transmission and distribution investment, avoided line losses, avoided ancillary services, avoided environmental compliance costs, avoided credit and collection costs, and increased resilience. [31]
- Targeted non-wire alternatives (NWA) to delay or avoid specific wires investment
    - Examples include non-wire alternatives or non-wire solutions currently being implemented in Ontario[32] and New York[33].

It is important to note that geographically targeted NWA in these jurisdictions have been introduced more recently than jurisdiction-wide peak load management DR programs while both approaches are currently being used in parallel with one another. This allows for broad demand response programs to be implemented on an ongoing basis due to their system-wide benefits while geographically targeted NWA procurements (through specific RFPs) can be used to address specific infrastructure constraints for a more discrete period of time. This layering of DR programs also helps to build and maintain market capacity to deliver demand flexibility (through ongoing programs) that can be leveraged and ramped up to deliver enhanced flexibility in areas of highest need.

Sectors and technologies

DR programs are used to target demand flexibility within all sectors although approaches can vary by sector based on the size of participants and enabling technologies available for each.

Since commercial and industrial (C&I) facilities use the most power of any consumer class, they also offer the largest DR resources by site. These consumers are often targeted using behavioural DR programs where there is flexibility in how they respond to a DR event. For example, some facilities will use existing operators to manually respond to the events by reducing equipment load according to their pre-defined DR plan, or facilities may choose to automate the demand response and use control systems that automatically reduce loads when a DR event is called. The facility (and the DR aggregator supporting them) will then be compensated based on the load reduction measured during the DR event compared with baseline electricity usage (e.g., electricity used in recent non-event days).

While residential DR potential is not as large per site, there are consumer technologies that can be used to engage a very large number of participants and create significant economies of scale for residential DR programs. The most common type of residential DR technology is a smart thermostat program. These devices are widely used and offer a direct channel to communicate with and recruit potential participants. They also have built-in ability to automate DR actions and offer an easy way for participants to opt-out of events. While opting out is a key feature of DR programs to ensure participants remain in control of their comfort, it is relatively modest and predictable so a large program can

[31] American Council for an Energy Efficient Economy (ACEEE). 2026. *Database of State Efficiency Screening Practices (DSP).* Retrieved from https://www.aceee.org/database-state-efficiency-screening-practices.

[32] Ontario Energy Board. 2024. *Non-Wire Solutions Guidelines for Electricity Distributors.* Retrieved from https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2024-03/OEB_2024%20NWS%20Guidelines_20240328.pdf.

[33] Joint Utilities of New York. 2026. *Non-Wire Alternatives (NWA).* Retrieved from https://jointutilitiesofny.org/nwa-opportunities.

still meet overall peak load reduction targets. Smart technologies (including behind-the-meter batteries and smart charging for electric vehicles) have built-in device telemetry that provides a record of the DR activity relative to operations during non-event days. It is common for this device telemetry to be used to compensate DR participants given the speed and ease of accessing the data. Given Alberta is not yet fully AMI-enabled, device telemetry also offers a way to measure and compensate residential DR participants without needing to wait for AMI and meter data management systems to be fully enabled across the province before being used to help manage grid affordability and reliability. Once a suitable level of AMI is fully enabled in Alberta, that would create opportunities to add behavioural DR programs to residential and small commercial sectors as a way to enhance DR program options available to those consumer types.

It should be noted that some DR procurement, such as NWA initiatives, are sector- and technology-agnostic, and do not limit the consumer types that can participate.

Recommendation for Alberta

While Alberta is currently limited with its next generation AMI deployment, there are several common types of DR programs, which do not require any changes to metering infrastructure or meter data management systems, that should be implemented in the short term in order to increase demand flexibility on the system and deliver DR benefits outlined above:

1) DR programs for C&I facilities with existing interval meters, and

2) Device-based DR programs using established smart technologies such as smart thermostats, smart electric vehicle chargers and behind-the-meter batteries.

The implementation of these programs should also be led by electricity distributors in the province so they can be used for supporting both local and bulk system needs. This provides the best opportunity to maximize the usefulness of distribution-connected DR resources, fits well with the existing visibility of consumers at the distribution level (compared with visibility at the AESO level), and enables direct integration with distribution system planning.

While programs led by distribution utilities are common in other jurisdictions, there remain barriers to their implementation in Alberta. These barriers are somewhat different for distributors regulated by the Alberta Utilities Commission (AUC), and those regulated by either municipal councils or their Rural Electrification Association (REA) board.

AUC-regulated distributors

For AUC-regulated electric distributors (ATCO, ENMAX, EPCOR and FortisAlberta), there is currently a financial disincentive associated with DR programs as they may impact each company's ability to earn a return on their capital investments. While the benefits of DR programs go beyond avoided distribution wires investments, this is a concern that is directly addressed in other jurisdictions in order to place these programs on a level playing field with other types of investments (or even make them more financially attractive to distributors than traditional investments). The result is lower overall costs for consumers given the positive benefit-cost analysis required to approve DR expenditures. For example:

- A 2020 study completed by the American Council for an Energy-Efficient Economy (ACEEE) included case studies for seven states related to the Performance Incentive Mechanisms (PIMs) for strategic demand

reduction.[34] Available performance incentives covered a wide range of potential values and were generally based on a percentage of either investment levels or net benefits generated.

State	Key design features	Maximum available incentive*
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement	Lesser of 5% of aggregate annual contract value or $500,000
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, growth rate achieved, and NWA assessment costs	15% of demand response spending
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget
Rhode Island	Cash reward (exempt from utility ROE cap) based on achievement of peak demand reduction, structured as a shared savings mechanism	45% of net benefits
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion	A portion of 100 basis points for SDR performance (currently approved at 65–70 basis points total)
Massachusetts	Portfolio-wide incentive; incentive based on performance from 75% to 125% of the PIM goals	5.4% of cumulative budget for program costs

***This is based either on the most recently complete performance period or the current performance period, depending on the age of the incentive.**

- A more recent assessment of PIMs for geographically targeted NWA projects generated a similar range of available incentives, which resulted in a 25% Margin on Payment (MoP) for distributors being implemented for NWA projects in Ontario (up to a maximum of 50% of the net benefits delivered).[35, 36]

These jurisdictions provide valuable examples for how a primary barrier to distribution-led DR programs (faced by AUC-regulated distributors in Alberta) can be overcome. It should be noted that the incentive mechanisms in all of these jurisdictions were created within a supportive policy and regulatory environment first established by

[34] Gold, R., et. al. 2020. *Performance Incentive Mechanisms for Strategic Demand Reduction.* American Council for an Energy-Efficient Economy (ACEEE). Retrieved from https://energyinnovation.org/wp-content/uploads/2020/02/Performance-Incentive-Mechanisms-for-Strategic-Demand-Reduction.pdf.

[35] Borden Ladner Gervais LLP. 2025. *OEB proposes incentive framework for third-party DERs with margin on payments*. Retrieved from https://www.blg.com/en/insights/2025/06/oeb-proposes-incentive-framework-for-third-party-ders-with-margin-on-payments.

[36] It is interesting to note this study also indicated that distributors in Australia are able to receive a 50% MoP on the cost of demand management projects (total incentives cannot exceeding 1% of their allowed revenue or the project's net benefits).

government. In comparison, there is currently a significant gap in policy and regulations in Alberta to enable successful DR programs compared with these other jurisdictions.

Distributors regulated by municipal councils or REA boards

For distributors governed by municipal governments (e.g., Red Deer and Lethbridge) or REA boards, their ability to add the cost of DR programs to rates is different than AUC-regulated distributors (they can already be approved by their municipal council or board), but they face challenges with limited economies of scale to assess and implement DR programs. In order to help overcome this barrier, it is recommended that there be opportunities for distributors to work together on DR programs so they can opt-in to larger initiatives that provide suitable economies of scale and acceptable returns on the investment of all participating distributors.

Roles for other actors

When implementing DR programs in Alberta, it is also recommended that there be a role for the competitive marketplace (including electricity retailers and DR aggregators) to recruit and manage participants. This is a successful model used in other jurisdictions and would fit well with Alberta's competitive market for electricity retail.

Enabling competition within the DR market can take several forms and usually evolves over time, as seen in other jurisdictions. To start, a standard offer approach could be taken for programs where DR aggregators (including retailers) are offered pre-defined compensation for signing up participants for a given DR season (could be annually, or based on summer and winter seasons). This approach helps to build capacity within the DR market by providing known compensation for recruiting and onboarding participants (within the pre-defined procurement limits for the program). Once capacity has been sufficiently established and the market has matured, it is then common to consider introducing competitive processes where DR capacity is procured based on bids received from aggregators or individual large participants for at least a portion of the DR resources procured in a jurisdiction.

Recommended next steps

This recommended approach to distribution-led DR programs is also the basis for a new demonstration project being led by the Alberta Energy Efficiency Alliance in collaboration with several distribution utilities in the province. This DR demonstration includes both a C&I DR program as well as a smart thermostat program. The demonstration is expected to simulate a variety of DR uses including responding to very high and very low temperature conditions (which correlates with system peaks), emergency events and local distribution constraints. While the demonstration will involve a relatively small number of participants and technologies (based on the amount of funding[37] secured for the project), it is designed in a way that could be ramped up and extended if additional funds were available.

Ultimately, however, it will be necessary for an effective regulatory framework to be established in Alberta to enable DR programs to be leveraged at the scale seen in other jurisdictions. As mentioned, this most often begins with government establishing a policy and regulatory framework that allows distributors to be financially incentivized to assess, develop and deliver DR programs that are in the economic interest of ratepayers.

[37] Funding was secured from Prairies Economic Development Canada, Alberta Innovates, Alberta Ecotrust Foundation, the Alberta Real Estate Foundation, EPCOR Distribution and Transmission, FortisAlberta, ATCO Electric, ATCO Gas and APEX Utilities.