Alberta ENERGY EFFICIENCY ALLIANCE

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Demand Side Management Opportunities for Alberta's Electricity System

Research Summary
October 2025

This report is a collaboration between the Alberta Energy Efficiency Alliance and the Energy Futures Lab.

About The Alberta Energy Efficiency Alliance

The Alberta Energy Efficiency Alliance (AEEA) is a member-based organization with a diverse group of stakeholders actively working to increase energy efficiency uptake in Alberta. Since 2007, AEEA has been an inclusive forum for communication, collaborative problem solving and coordinated action. AEEA's current work on utility Demand Side Management (DSM) is focused on reducing utility costs and increasing economic opportunities across the province.

About The Energy Futures Lab

The Energy Futures Lab (EFL) is a leading platform for energy transition innovation, based in Alberta. Since 2015, the Lab has convened a diverse network of innovators, influencers, and decision-makers from across the energy system to tackle Canada's most complex energy challenges. In an era of growing polarization, the Lab has earned a reputation for convening trusted, non-partisan spaces where stakeholders and Rights and Title Holders can work together on practical, system-level solutions. Through deep collaboration, the Lab drives innovation that is grounded in community, informed by expertise, and aligned with a resilient, inclusive, and low-emissions energy future for Canada. EFL is a Generate Canada solution space.

Authors

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Disclaimer

This advice does not necessarily represent, in part or in whole, the views of any individual or organization. In addition, the opinions expressed in this report do not necessarily reflect those of AEEA's or Generate Canada's respective Board of Directors, funders, donors or advisors.

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Executive Summary

Demand Side Management (DSM) is a widely-recognized tool for increasing the affordability and reliability of electricity systems around the world. This research summary compares Alberta's DSM approach to comparable jurisdictions, identifies gaps in current approaches and recommends actions for increasing the use of DSM in the province.

What is Demand Side Management?

DSM refers to a suite of programs and initiatives designed to influence how consumers use electricity, helping to optimize grid operations and optimize the use of existing infrastructure. Common approaches to engaging consumers to help manage demand in other deregulated jurisdictions include:

- Demand response (DR) and energy efficiency programs
- Advanced rate structures or pricing mechanisms such as time variable rates (TVR), and direct participation in ancillary services and wholesale markets

Benefits of DSM

DSM is widely used within electricity systems to deliver the following benefits:

- Improving the **affordability** and **reliability** of utilities by helping consumers be more efficient and flexible in how and when they use electricity and natural gas.
- **Optimizing** use of existing infrastructure (including generation, transmission and distribution) by reducing peak demand and grid pressure, and in some cases deferring the need for higher-cost investments.
- Increasing **consumer satisfaction** by improving their ability to influence their bills and leverage on-site devices.
- Generating opportunities for **local businesses and trades**, creating a predictable demand for work and attracting new companies to Alberta by increasing demand for DSM services in the province.
- Cost-effectively **reducing emissions** and complementing other emission reduction efforts.

These benefits also work to enhance the **economic competitiveness** of a jurisdiction by lowering the cost of living and cost of doing business.

Executive Summary

DSM in Alberta vs. Other Jurisdictions

This study includes a review of six jurisdictions with similar electricity market structures to Alberta: Texas, California, New York, the United Kingdom, Australia and Ontario. All of these jurisdictions were found to use a combination of approaches to DSM including enabling participation of consumers in ancillary services and wholesale markets (either directly or through aggregators), implementing time-varying rates, and offering a range of demand response and energy efficiency programs to consumers.

In Alberta, consumers currently have the option to participate directly in ancillary services and wholesale markets, and opt-in to time-varying rates (with limited uptake to date). However, of the jurisdictions reviewed, Alberta is currently the only one without demand response or energy efficiency programs available to all consumers.

DSM Opportunities for Alberta

Based on the review of Alberta's current approach to DSM compared with other jurisdictions, there are some low-investment, low-barrier opportunities to help manage system costs and allow consumers to play a greater role in contributing to system reliability and affordability. The following key recommendations have been identified:

1. **AESO should monitor changes to the demand flexibility of large loads in the province given the anticipated changes to price signals for these consumers.**

   Large industrial loads are currently the most responsive to fluctuating price signals in Alberta's electricity system. These price signals are expected to change, however, as changes are made to the province's wholesale electricity market and potentially to coincident peak demand charges (12-CP) as well[1]. A higher price cap in the wholesale market, but potentially reduced ability to avoid transmission costs, will create countervailing effects on market behaviour, leading to uncertain outcomes related to demand flexibility.

   Regardless of the impacts of these changes, the value placed on demand flexibility is not expected to be as great as the value of lost load (VoLL), which would result in an underdevelopment in demand response related to emergency events. Consideration should be given by the AESO as to whether a mechanism similar to the Emergency Response Service (ERS) in Texas should be introduced in order to create a greater incentive and formal mechanism for loads of all sizes to provide contracted demand flexibility during grid emergency events. It should be noted that in Texas, emergency response services are both directly procured by the grid operator and provided by wires utilities through their load management programs. A similar approach is recommended for Alberta where distribution-led demand response programs can be used to help support both local and bulk system needs.

1 Alberta Utilities Commission Decision 26911-D01-2022, page 16, paragraph 76.

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2. **AESO and utilities should monitor efforts to increase direct participation of smaller loads in existing markets.**

   A recently-announced demonstration project is expected to explore the ability to aggregate residential loads with behind-the-meter batteries for participation in the province's wholesale and ancillary services markets as a virtual power plant (VPP). While this is largely a consumer offering for the private sector to advance, there is merit in identifying whether there are actions that the system operator, regulated entities or the provincial government could take to remove barriers for this business model to grow in Alberta, providing new options for consumer participation in the electricity system.

3. **Government should explicitly enable the use of DSM programs for all consumer groups – starting with demand response.**

   Given the broad use of DSM programs in other jurisdictions, positive consumer sentiment, and their compatibility with other approaches to DSM, it is recommended that use of this mechanism be increased in Alberta due to the affordability and reliability benefits delivered in all other jurisdictions reviewed.

   The end goal of the DSM programs should be a portfolio of approaches that serves all market segments and a range of market needs (as seen in other jurisdictions), but it is recommended to start with a narrower scope in order to build capacity and understanding of DSM programming in the short-term.

   Demand response (DR) is a component of DSM that has seen interest from a number of entities (including the AUC, AESO and distribution utilities) and is well positioned to be the focus of an initial effort to advance DSM in Alberta. Direction from the provincial government for all of these groups to pursue DR within their areas of authority would enable multiple approaches to be advanced (as seen in other jurisdictions) to support the reliability and affordability of both the bulk system and local distribution systems. There are many examples of approaches for coordination between these various groups that can assist with multiple entities pursuing DR initiatives in parallel.

While Alberta currently trails other jurisdictions in DSM implementation, there are several ways to start catching up. Creating new initiatives to advance DSM in the province will provide consumers, distribution utilities and the system operator with new tools to manage both affordability and reliability of the electricity system, and to deliver economic benefits across the province.

Background

What is Demand Side Management (DSM)?

DSM refers to a suite of programs and initiatives designed to influence how consumers use electricity, helping to optimize both grid operations and the use of existing infrastructure. DSM leverages consumers' flexibility to help balance supply and demand, particularly during periods of grid constraint, at a lower cost than relying solely on supply-side investments. It can be used as a flexible toolkit - a set of different tools or combinations of tools that can be deployed depending on the needs or viewpoint of both the customer and the system operator/utility.

System operators and utilities often have complex objectives that can be partially or fully achieved through a combination of DSM programs and initiatives. Their objectives are typically a combination of technical, economic, political, and social. It is typical for system operators and utilities to design and offer a variety of programs to consumers that will enable them to achieve their system objectives. Figure 1 below illustrates the various ways DSM programs and initiatives can be utilized (adopted from the AEIC Load Research Manual).

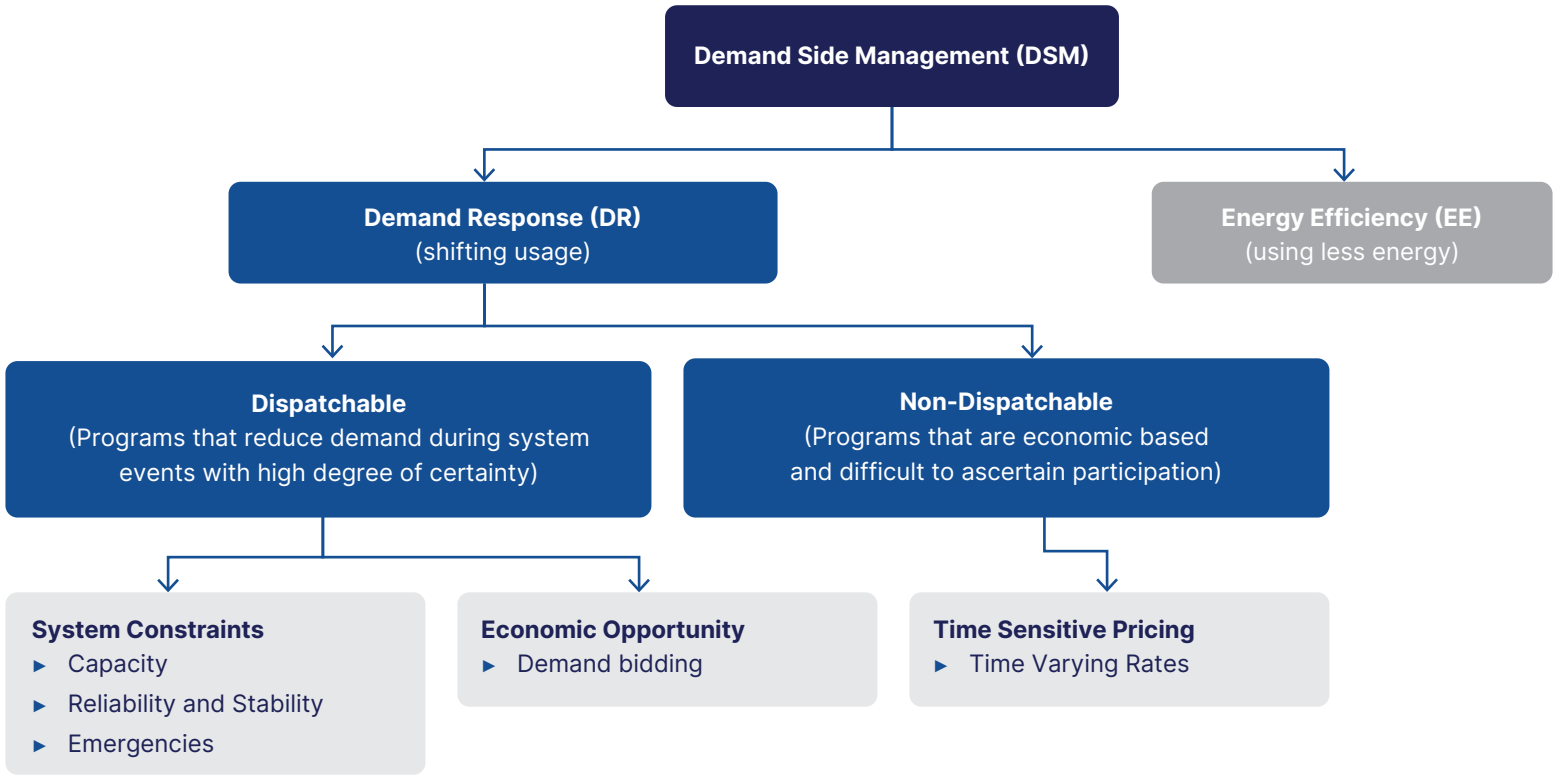


Figure 1: Different demand side management programs and initiatives

Background

From a consumer perspective, DSM programs, such as those listed below, are an opportunity to receive a reward, typically financial, for changing their electricity usage patterns:

- **Demand Response (DR) programs:** Financial incentives are offered to consumers who agree to reduce or shift their electricity use during peak periods or grid emergencies. Consumers may see this incentive appear directly on their bill or through other mechanisms, such as direct payments or gift cards, depending on the program design or aggregator preference. DR can be done manually by consumers or automated through equipment/device control systems, such as building energy management systems and smart equipment or appliances. These can be combined with cloud-based software/apps to create a seamless customer experience.

  Typical end-use technologies for DR programs include control systems for water heaters, air conditioners, appliances, heat pumps, fans, motors, compressors, chillers, industrial process equipment, behind-the-meter (BTM) onsite generation or energy storage, and electric vehicle (EV) chargers.

- **Advanced Rate Structures or Pricing Mechanisms:** Time-varying approaches to electricity prices, such as time-of-use (TOU) rates, encourage consumers to shift usage to off-peak hours, while real-time pricing uses market prices to encourage consumers to use electricity during low price hours that vary over time. If consumers choose to shift their usage, they will pay less for their electricity use during those hours. Depending on the rate structures, this can reduce their overall electricity bill. Typical technologies for responding to price signals are the same as those listed for DR programs, including manual and automated responses.

- **Energy Efficiency programs:** Support consumers in choosing high-efficiency alternatives when upgrading homes, buildings or industrial facilities, thereby lowering their overall consumption and electricity bills. These upgrades can include new equipment, updating building envelopes, and automating energy management systems. Depending on the program structure, costs for upgrades can be shared between the owner and the program administrator. These programs are among the most cost-effective in lowering overall utility bills for homes and businesses, while also helping to reduce overall electricity system costs - thereby reducing the cost of living and doing business in the province.

How is DSM related to Non-Wires Solutions?

Non-wires solutions (NWS) are actions that reduce or defer the need for investment in distribution and/or transmission infrastructure (e.g. increasing the capacity of electrical wires and other infrastructure such as substations and feeders), which are typically paid for through wires tariffs. DSM can be used as a NWS, although it is also often used to meet other objectives, such as increased system-wide affordability and reliability, and isn't always referred to as a NWS. The definition of NWS also extends beyond DSM as there are front-of-the-meter (FTM) technologies that can be utilized as NWS.

Background

How is DSM related to Distributed Energy Resources?

The term Distributed Energy Resources (DER) is often used to describe technologies connected to the distribution portion of the electricity system. DERs can be connected either behind the meter (BTM) at a consumer site, or in front of the meter (FTM) directly to the grid. DSM programs and initiatives can use, manage, and/or orchestrate BTM DERs to deliver grid services and reduce consumer electricity consumption. Another way to think about this is that DSM is a set of actions and tools that use and manage DERs.

Figure 2 below illustrates the connection between DSM, DERs and NWS.

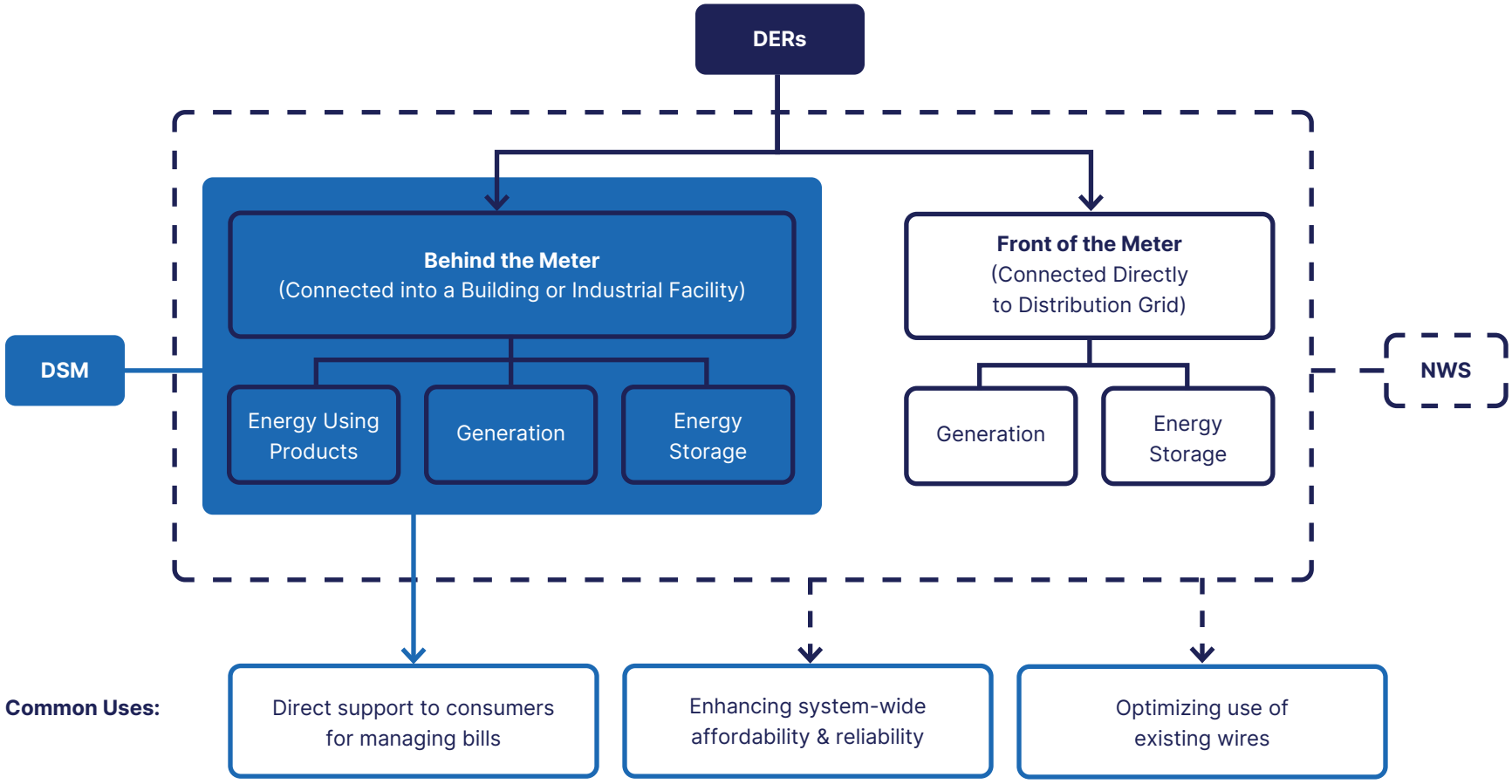


Figure 2: Visual illustration of DSM, DERs and NWS

Background

As DER adoption increases, the opportunity to deploy advanced DER management and orchestration also increases. This can lead to further DSM programs in addition to traditional energy efficiency and demand response initiatives. Figure 3 below illustrates the evolution of DSM programs.

Application	Traditional Energy Efficiency Programs	Traditional Demand Response Programs	Integrated DSM & DER Management
Description	Delivering the same service using less energy	Voluntary reduction in consumption during tight supply periods	Bringing more BTM DERs into utility programs that lay outside traditional DR or EE programs

Figure 3: The evolution of DSM and DER management[2]

2 Adapted from "Demand Side Management Opportunities for Alberta" https://www.aeea.ca/wp-content/uploads/2025/03/DSM-Cost-Benefit-Report-for-Alberta.pdf

Background

Benefits of DSM

Investment in DSM in Alberta would provide the following benefits:

- Improving the **affordability** and **reliability** of utilities by helping consumers be more efficient and flexible in how and when they use electricity and natural gas.
- **Optimizing** use of existing infrastructure (including generation, transmission and distribution) by reducing peak demand and grid pressure, and in some cases deferring the need for higher-cost investments.
- Increasing **consumer satisfaction** by improving their ability to influence their bills and leverage on-site devices.
- Generating opportunities for **local businesses and trades**, creating a predictable demand for work and attracting new companies to Alberta by increasing demand for DSM services in the province.
- Cost-effectively **reducing emissions** and complementing other emission reduction efforts.
- Enhancing Alberta's **economic competitiveness** by lowering the cost-of-living and cost-of-doing-business in the province.

DSM in Other Jurisdictions

Given the multiple benefits listed above, investment into DSM programs across Canada and the U.S. exceeds $10 billion annually[3]. Ongoing DSM programs are in place in every other province in Canada and other jurisdictions with deregulated electricity markets such as Texas, California, the U.S. Northeast and Midwest, the U.K., and Australia. The structure of DSM programs in these jurisdictions is relatively similar and includes the following features regardless the market structure:

- Consumer programs for every sector (industrial, commercial and residential)
- Supporting a mix of demand response, energy efficiency, distributed generation, batteries and energy management solutions
- Oversight by the utility regulator
- Regulatory framework established by government (see examples in Appendix A)

It is universal for utility DSM programs to exist alongside other mechanisms such as procurement of ancillary services, wholesale markets, and time varying rates and/or wires tariffs. This combination of approaches working together is the most common way to approach DSM seen in other jurisdictions.

The following pages demonstrate this range of approaches to DSM in other jurisdictions, with a more detailed

3 https://cee1.org/images/pdf/2023_AIR_Final.pdf

Background

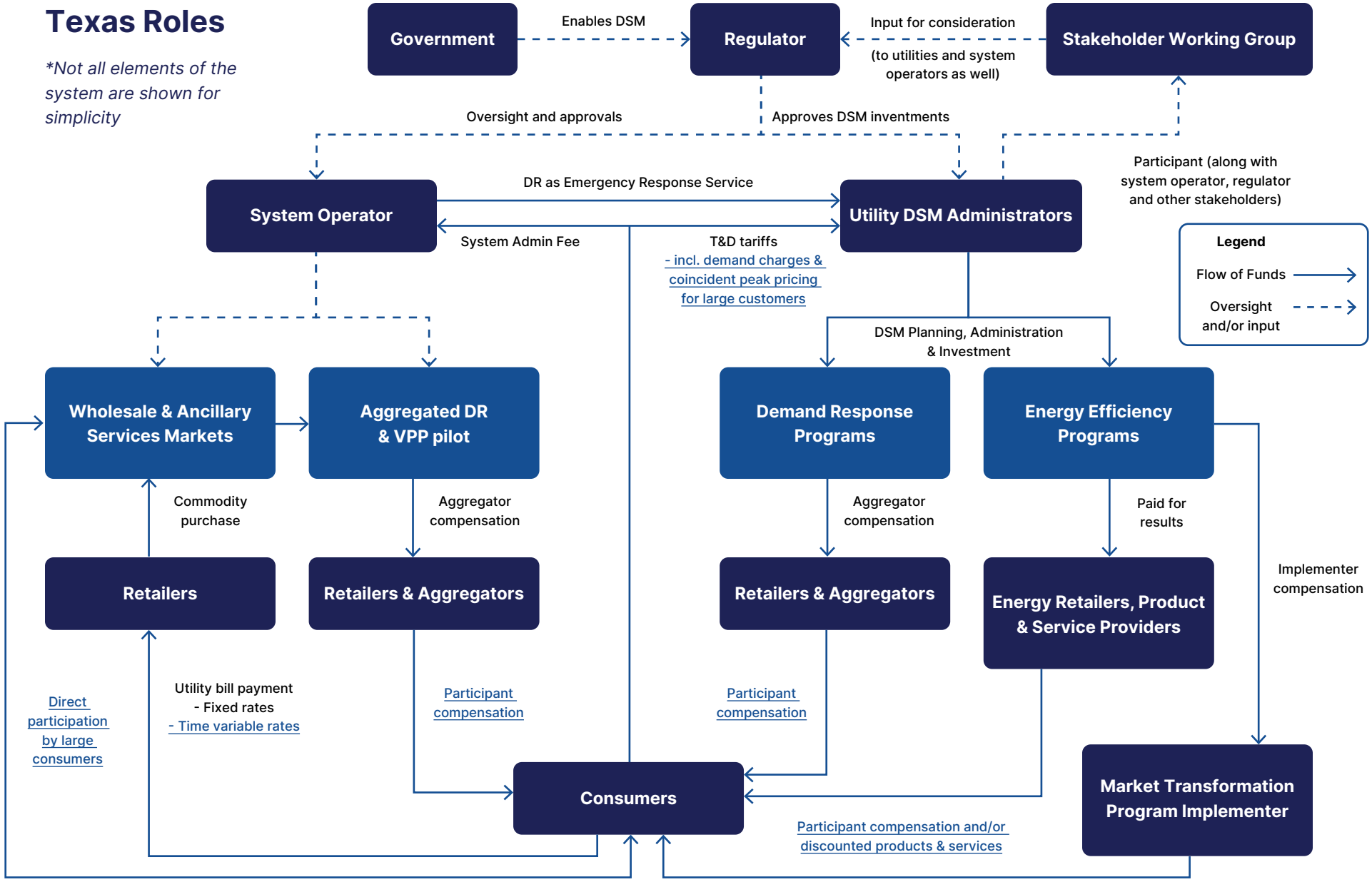
schematic that shows how utility DSM programs fit within the Texas electricity system. The key observation drawn from these resources is that there are three main approaches to engaging the demand side of these electricity systems, and all approaches are in place in all jurisdictions reviewed. The approaches include a combination of:

- **Consumer DSM programs** where consumers are supported to incorporate DR, EE, DG, batteries and/or energy management into their business or home
- **Time variable price signals** through energy rates and/or transmission and distribution (T&D) tariffs (i.e. time varying rates)
- Participation in **ancillary services** and/or energy **wholesale markets**

Once again, all these approaches to DSM are undertaken in a complementary manner in each of these jurisdictions, offering consumers across all sectors a range of opportunities for managing how and when they use electricity.

Texas Roles

**Not all elements of the system are shown for simplicity*



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

Figure 4: Approaches to demand side management in Texas

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 varying 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
Time related demand charges for transmission and/or distribution tariffs	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	

Note: Sources of information are listed in Appendix A.

Table 1: Comparison of approaches to demand side management across key jurisdictions

DSM Opportunities for Alberta

Barrier to DSM in Alberta

In all other jurisdictions, enabling DSM at scale has required a regulatory framework that allows cost-effective DSM investments to be approved by the utility regulator. In Alberta, the AUC denied gas and electric utility DSM funding requests in 2011, 2012 and 2022, creating significant uncertainty for the advancement of DSM in the province.[4,5,6] These denials reflected the absence of clear provincial regulations enabling utility-administered DSM.

Clear direction from the Government of Alberta would enable the AUC to approve DSM initiatives that are in the public interest, delivering benefits similar to those seen in comparable jurisdictions.

Current State of Demand Side Management in Alberta's Electricity System

As seen in the jurisdictional review of other deregulated jurisdictions (Table 1), there are several ways to support consumers to influence how and when they use electricity. Table 2 summarizes an assessment of each of those approaches within the Alberta context and compares them with Texas – the jurisdiction with an electricity market structure that most closely resembles Alberta's. Public polling from the Alberta Smart Grid Consortium is also referenced to indicate the level of public support for different approaches to DSM for residential, commercial, and farm consumers.[7]

4 Alberta Utilities Commission Decision 2011-450
5 Alberta Utilities Commission Decision 2012-091
6 Alberta Utilities Commission Decision 26615-D01-2022 and Decision 26616-D01-2022
7 https://albertainnovates.ca/wp-content/uploads/2022/01/Electricity-Customer-Research-Study-Final-Report-2022-01-20.pdf

Mechanism for Engaging Demand	Texas (current)	Alberta (current)	AB Smart Grid Consortium Polling	AB Timing Considerations
Direct participation by large loads in ancillary services and/ or wholesale markets	Currently enabled	Currently enabled	N/A	Already in place
Aggregation of small or medium-sized loads for participation in ancillary services and/ or wholesale markets	Currently enabled through aggregator specific rules	Currently allowed, but no aggregator-specific rules in place	Res: 54% favourable Comm: 63% favourable Farm: 73% favourable	Not currently reflected in REM consultation; recent pilot project funding announced[7]
Time varying rates on electricity consumption	Currently offered as an optional rate	Available for consumers with interval meters	Res: 51% favourable Comm: 37% favourable Farm: 46% favourable	Shorter settlement intervals expected by 2040
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	Coincident Peak Demand (12-CP) pricing currently in place for bulk transmission system	N/A	Bulk system rates under review – anticipate reduced weight placed on 12-CP methodology
Demand response programs by wires utilities or retailers	In place for T&D utilities	None	N/A	12 to 18 month implementation common, but no framework currently in place
Energy efficiency programs by wires utilities or retailers	In place for T&D utilities (gas utilities as well)	None	All sectors: 92% favourable	

Table 2: Current status of demand side management approaches in Alberta (AB)

8 https://www.eralberta.ca/projects/details/an-innovative-virtual-power-plant-solution-to-reshape-alberta-electricity-grid-and-enable-the-widespread-adoption-of-renewable-energy-and-high-energy-tier-buildings/

DSM Opportunities for Alberta

Reviewing the current status of DSM in Alberta's utility system relative to Texas (and other jurisdictions listed in Table 1), the Alberta-specific public polling available, and the timing considerations listed in Table 2, produces the following observations:

Direct participation by large loads
Large industrial loads in Alberta currently have the greatest ability to engage directly with the AESO's ancillary services (including operating reserves) and wholesale electricity markets, allowing them to actively manage their electricity costs and contribute to grid reliability.

Opportunities for large loads to respond to price signals is expected to reduce, however, as Coincident Peak Demand (12-CP) pricing within the Independent System Operator (ISO) tariff (currently the largest contributor to peak shifting in the province) is expected to be changed in the next update to the tariff.[9] In contrast, a proposed increase to the price cap in Alberta's wholesale electricity market is expected to increase the incentive for large loads to be price responsive.

Discussions with Alberta Direct Connect (ADC) – the association that represents many of the transmission-connected large industrial facilities in the province – indicates that there is interest in increasing opportunities for large industrial facilities to provide grid services by being flexible loads.

Aggregation of small or medium-sized loads
Aggregation of loads for participation in the province's ancillary services markets currently occurs through mechanisms such as Operating Reserves. Participating loads are primarily industrial facilities with the flexibility to reduce their regular electricity demand within 10 minutes of notice and remain off for approximately 25 to 45 minutes. Examples include cold storage and gas compression facilities.

Small and medium-sized loads are not currently excluded from participating in the AESO ancillary services and wholesale electricity markets, however, there is currently limited aggregation of small and medium loads occurring.

A multi-site BTM battery demonstration project by the Landmark Group of Companies, recently funded by Emissions Reduction Alberta (ERA), is expected to help identify further market opportunities and barriers for increasing the aggregation of small consumers in the AESO ancillary services and wholesale electricity markets. This demonstration is expected to require special treatment by the regulated distribution utility, EPCOR, in order to access meter data that is more detailed than the standard monthly cumulative data currently provided for residential customers.

9 Alberta Utilities Commission Decision 26911-D01-2022 page 16, paragraph 76.

DSM Opportunities for Alberta

Time-varying rates

Time-varying rates (TVR) are already possible in Alberta for large- and medium-sized commercial and industrial consumers for both energy prices and wires charges, although TVR distribution rates for large commercial consumers currently vary by service territory.[10] Residential and small business consumers remain on monthly cumulative billing, which is not currently compatible with time-varying rates. The AESO and Government of Alberta have both indicated that shorter settlement within all parts of the electricity system is expected by 2040, given the time required for all meters in the province to be able to read at 5-minute intervals.[11] Deployment of time-varying rates across all customer classes will require advanced technical capabilities for both distributors and retailers. Distributors will need advanced metering, communications, data management and billing infrastructure, while retailers will need upgrades to their data management and billing infrastructure. These capabilities will require significant capital investment and impact ongoing operational costs.

If technical capabilities were in place, however, there could be opportunities for time-varying rates to be partially expanded before shorter settlement is established for all customer classes. For example, this could occur by enabling voluntary time-varying energy rates, or by increasing the use of time-varying rates on transmission and/or distribution charges.

Early indications from FortisAlberta's Electric Vehicle Smart Charging Pilot, which compared direct load control (DLC) with time-of-use (TOU) rates, have pointed to some advantages of DLC compared with TOU for managing system ramping (up and down), reducing "shadow peaks" and reducing strain on distribution infrastructure.[12] Polling from the Alberta Smart Grid Consortium and evidence from other jurisdictions also shows that a majority of consumers are not favourable towards TOU rates. DR programs are typically offered before TOU rates to help build consumer familiarity with being a flexible load before the introduction of mandatory TVR. These programs can also include DLC to help manage the impact of shadow peaks before TOU is broadly used.

Demand side management programs

While consumer DSM programs (for demand response and energy efficiency) were found in every other jurisdiction reviewed, Alberta is currently the only one that does not have annual investment through the utility system into DSM programs. DSM programs are generally well received by customers, do not require upgrades to metering infrastructure, can be set up in less than 12 months from program approval[13] and are compatible with a variety of market structures, as demonstrated by their successful deployment in a range of different jurisdictions.

While these different approaches for demand side management may appear as options to choose between, research shows that these approaches are all used in a parallel and compatible way in every jurisdiction reviewed (see Table 1). It is recommended that the same strategy be used in Alberta where a combination of approaches are used to engage consumers in order to unlock greater affordability and reliability benefits across the province.

10 See Enmax Distribution Tariff and FortisAlberta Rates, Options and Riders Schedule for examples

11 https://www.aeso.ca/assets/direction-letters/Direction-Ltr-from-Minister-REM_Tx-Policy_10Dec2024.pdf

12 https://www.nber.org/papers/w32886

13 Based on direct communication with demand response program implementers.

DSM Opportunities for Alberta

Recommendations for Advancing DSM in Alberta

Given the current status of different approaches to DSM in Alberta, described above, the following are recommended next steps:

1. **AESO should monitor impacts from changes to the wholesale market and 12-CP, and advance other mechanisms to incentivize flexibility of larger loads.**

   Large industrial loads are currently the most responsive to fluctuating price signals in Alberta's electricity system. These price signals are expected to change, however, as changes are made to the province's wholesale electricity market and potentially to coincident peak demand charges (12-CP) as well. A higher cap in the wholesale market, but potentially reduced ability to avoid transmission costs, will create countervailing effects on market behaviour, leading to uncertain outcomes related to demand flexibility.

   Regardless of the impacts of these changes, the value placed on demand flexibility through both the wholesale market and ISO tariff is not expected to be as great as the Value of Lost Load (VOLL), which would result in an underdevelopment in demand response related to emergency events. Consideration should be given by the AESO as to whether a mechanism similar to ERCOT's Emergency Response Service (ERS) should be introduced in order for loads of all sizes to have a greater incentive to provide flexibility during grid emergency events. Consideration should be given by the AESO as to whether a mechanism similar to the Emergency Response Service (ERS) in Texas should be introduced in order to create a greater incentive and formal mechanism for loads of all sizes to provide contracted demand flexibility during grid emergency events. It should be noted that in Texas, emergency response services are both directly procured by the grid operator (ERCOT) and provided by wires utilities through their load management programs.

2. **AESO and utilities should monitor efforts to increase the direct participation of smaller loads in existing markets.**

   The demonstration project being undertaken by Landmark and its partners, mentioned above, is expected to explore the ability to aggregate residential loads with BTM batteries for participation in the province's wholesale and ancillary services markets as a virtual power plant (VPP). While aggregating small prosumers for participation in existing markets is largely an opportunity for the private sector to advance, there is merit in identifying whether there are actions that the system operator, regulated entities or provincial government could take to remove barriers for this business model to grow in Alberta providing new options for consumer participation in the electricity system.

DSM Opportunities for Alberta

3. Government should explicitly enable the use of DSM programs for all consumer groups – starting with demand response.

Given the broad use of DSM programs in other jurisdictions, positive consumer sentiment, and their compatibility with other approaches to demand side management, it is recommended that the use of this mechanism be increased in Alberta due to the affordability and reliability benefits delivered in all other jurisdictions reviewed.[14]

The end goal of the DSM programs should be a portfolio of approaches that serves all market segments and a range of market needs (as seen in other jurisdictions), but it is recommended to start with a narrower scope in order to build capacity and understanding of DSM programming in the short-term.

Demand Response (DR) is a component of DSM that has seen interest from a number of entities (including the AUC[15,16], AESO[17] and distribution utilities[18,19]) and is well positioned to be the focus of an initial effort to advance DSM in Alberta. **Direction from the provincial government for all of these groups to advance DR within their areas of authority** would enable multiple approaches to be pursue (as seen in other jurisdictions) to support the reliability and affordability of both the bulk system and local distribution systems. There are many examples of approaches for coordination between these various groups that can assist with multiple entities pursuing DR initiatives in parallel. The following are key aspects for consideration:

- DR programs exist for all sectors (industrial, agriculture, commercial and residential) and can target a range of technologies (from sophisticated energy management systems at large facilities to smart thermostats in small buildings) as well as behavioural demand response (i.e., the customer controls how they respond to the DR event).
- These programs provide a higher degree of predictable demand flexibility than many other approaches (such as TOU rates) as the DR resources are contracted to provide a well-defined response when DR events are called. DLC also allows for a more tailored approach to ramping DR resources (on and off the system), which reduces shadow peaks and stress on upstream infrastructure.
- DR programs can also be approached in a way that provides incentives for electricity retailers, DR aggregators and product suppliers to directly engage their customers and serve as conduits for participation in DR programs. This approach helps build market capacity and customer familiarity with becoming a flexible load and grid resource prior to broader deployment of other initiatives, such as TVR rates.

14 See for example: https://scorecard.efficiencycanada.org/
15 https://media.auc.ab.ca/prd-wp-uploads/regulatory_documents/Reference/28542_Inquiry-ModuleB-Report.pdf
16 https://www.auc.ab.ca/net-zero-analysis-of-albertas-electricity-distribution-system/
17 https://www.aesoengage.aeso.ca/strategic-reserves
18 https://engage.auc.ab.ca/consultations/engagement-on-enabling-time-varying-rates-for-residential-and-other-electricity-customers-in-alberta/
19 https://www.aeea.ca/dsm

DSM Opportunities for Alberta

- In the near-term, DR programs can be launched without any changes to meters, data management or billing systems.
- In some DR programs, DR aggregators enroll customers directly into the programs, and use existing device telemetry and internet connection to connect to customer-owned smart devices in homes and businesses. This allows the DR aggregator to directly control smart devices during emergency events and/or times of high demand and to measure the load reduction from each unique smart device. DR aggregators compensate consumers directly (in a variety of ways) for allowing them this direct control.
- Program examples that rely on device telemetry data include myEnergy Rewards (Ontario), Eco Shift (Nova Scotia), Peak Smart (Yukon), Demand Side Grid Support (California), Customer Battery Energy Sharing (Puerto Rico). Note that programs on this list continue to use device telemetry data even when AMI data is available due to the cost savings associated with this approach.
- In the long-term, both DR programs and TVR can leverage the capabilities of advanced metering, communications, data management and billing infrastructure to offer additional approaches to measuring and compensating consumers for being flexible loads.

Conclusion

Based on the work outlined above, the following key conclusions can be drawn:

- Demand side management provides multiple benefits to enhance the affordability and reliability of electricity systems.
- Other jurisdictions use a combination of approaches to engage consumers to influence how and when they use electricity. The combination of approaches used in all other jurisdictions reviewed include:
  - Customer DSM programs,
  - Direct participation in ancillary services and wholesale markets, and
  - Time varying rates.
- Time varying rates such as TOU rates should be approached carefully given the relatively negative consumer polling associated with it. In most jurisdictions, TOU rates have been initially introduced as voluntary. While voluntary uptake of TOU rates is typically relatively modest, it provides an opportunity to build market familiarity prior to wider adoption. Even in the case of Ontario, where TOU energy rates have become the default rate, options to opt-out of the TOU rates have been added to provide concerned consumers with an alternative approach to managing their electricity costs. Demand response programs can also be implemented in the short-term, using existing infrastructure, to build consumer capacity and familiarity with being a flexible load before broader deployment of TOU rates.
- In the longer term, it will be important to enable and leverage the capabilities of advanced metering, communications, data management and billing infrastructure systems to offer additional approaches to measuring and compensating consumers for being flexible loads. Additionally, as BTM DER adoption increases, DSM programming can be enhanced by greater DER management and orchestration, leading to enhanced DSM programming.
- Alberta is currently behind other jurisdictions, but has opportunities to advance DSM in the short term to enhance affordability and reliability.

Conclusion

Recommended next steps to increase demand side management in Alberta include:

- AESO to monitor how changes to the wholesale market and 12-CP impact the demand flexibility of large loads, and continue to advance new opportunities for large loads including, but not limited to, emergency demand response.

- AESO and utilities to monitor efforts to increase price responsiveness of small consumers through initiatives like the VPP demonstration being undertaken by Landmark. Consider changes to enable greater price responsiveness of small loads in the short term while working towards longer-term implementation of shorter settlement.

- Government to explicitly enable the use of demand response programs in the short term, using existing infrastructure, to enhance the tools available for managing both local and bulk system needs.

Appendix A: Jurisdictional Research Sources

Texas

Aggregator rules (ERCOT): https://www.ercot.com/files/docs/2020/08/31/Requirements_for_Aggregate_Load_Resource_Participation_in_the_ERCOT_Markets.doc

Time-of-use rates: https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Business/TX-Time-of-use-rate-FAQ.pdf

Coincident peak demand charges: https://medium.com/industrial-sun-insights/understanding-ercots-4cp-demand-charge-759c02034120

Demand response summary: https://www.ercot.com/files/docs/2023/05/19/ERCOT_Demand_Response__Summary_Spring_2023-update.pdf

- See slide 11 related to Key Issues for Demand Response in Texas on emerging thinking related to price responsive DR, local reliability and coincident peak pricing.

Legislation related to energy efficiency and peak demand reduction: https://capitol.texas.gov/tlodocs/82R/billtext/html/SB01125S.htm

California

DER & DR aggregation (CAISO): https://www.caiso.com/generation-transmission/generation/distributed-energy-resources

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/drp-registration-information

Time-of-use rates: https://energyregulationquarterly.ca/articles/time-of-use-rates-an-international-perspectives#sthash.jrly3OVY.dpbs and https://www.sce.com/business/rates/time-of-use/Time-of-Use-Rates-FAQs

Critical peak pricing: https://www.sce.com/business/rates/cpp

Demand response led by T&D Utilities: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr

Energy efficiency led by T&D Utilities: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-potential-and-goals-studies

Legislation related to energy efficiency savings and demand reduction: https://codes.findlaw.com/ca/public-utilities-code/puc-sect-454-55/

Appendix A: Jurisdictional Research Sources

New York

Aggregator rules: https://cpowerenergy.com/everything-you-need-to-know-about-new-yorks-new-der-aggregation-participation-model/

https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/NY-Sun/value-stack-overview.pdf

Time varying rates: https://www.nationalgridus.com/Upstate-NY-Home/Rates/Service-Rates

Demand response programs: https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Energy-Storage-for-Your-Business/Demand-Response-Programs

https://www.thermostatrewards.com/nationalgrid-ny/faq/

Energy efficiency programs: https://programs.dsireusa.org/system/program?state=NY

Order from the regulator regarding energy efficiency targets (includes consideration of peak demand savings): https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=217510&MatterSeq=55825

Australia

Aggregator registration: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration/register-as-a-small-generation-aggregator-sga-in-the-nem

Time-of-use rates: https://www.canstarblue.com.au/electricity/peak-off-peak-electricity-times/

Demand charges: https://energyaction.com.au/australian-electricity-network-tariffs/

DR and EE programs: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/electricity/new-2022_demand_side_engagement_strategy_final.pdf

https://www.energex.com.au/__data/assets/pdf_file/0006/1330818/Demand-Management-Plan-2024-25.pdf

https://www.redenergy.com.au/energy-industry/government-energy-efficiency-schemes

https://www.energy.vic.gov.au/victorian-energy-upgrades/about-the-veu-program

https://www.escosa.sa.gov.au/industry/reps/overview/reps

https://www.energysustainabilityschemes.nsw.gov.au/ess

https://www.wa.gov.au/government/announcements/energy-ahead-formerly-the-household-energy-efficiency-scheme

Legislative examples: https://www.energysustainabilityschemes.nsw.gov.au/ess-legislation

https://www.aemc.gov.au/rule-changes/distribution-network-planning-and-expansion-framew

Appendix A: Jurisdictional Research Sources

United Kingdom

Aggregated and Large Load participation in Short Term Operating Reserve: https://www.nationalgrid.com/sites/default/files/documents/STOR%20Frequently%20Asked%20Questions%20v2%20%281%29.pdf

Demand Flexibility Service for Households and Businesses: https://www.neso.energy/industry-information/balancing-services/demand-flexibility-service-dfs

Time of Use Rates: https://duracellenergy.com/en/news/when-is-the-cheapest-time-to-use-electricity/

https://energysavingtrust.org.uk/time-use-tariffs-all-you-need-know/

Demand Charges: https://uk.vtoman.com/blogs/news/demand-charges-everything-you-need-to-know

Local Flexibility Procurement: https://dso.ukpowernetworks.co.uk/flexibility

Energy Efficiency Obligation: https://www.ofgem.gov.uk/environmental-and-social-schemes/energy-company-obligation-eco

Legislation related to local flexibility procurement and energy efficiency obligation: https://www.legislation.gov.uk/uksi/2020/1401/regulation/4/made

https://www.ofgem.gov.uk/environmental-and-social-schemes/energy-company-obligation-eco

Ontario

Capacity auction: https://edgecom.ai/blog/what-is-demand-response-and-capacity-auction/

Time-of-use rates: https://www.oeb.ca/consumer-information-and-protection/electricity-rates

Industrial Conservation Initiative for Global Adjustment Class A customers: https://www.ieso.ca/Learn/Ontario-Electricity-Grid/Demand-Response

Conservation and Demand Management Framework: https://www.ieso.ca/-/media/Files/SaveOnEnergy/2021-2024-Conservation-and-Demand-Management-Framework-Mid-Term-Review.pdf

Local demand response: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/tdwg/tdwg-20220913-toronto-hydro-local-dr-pilot.pdf

Electric Demand Side Management Framework: https://www.ontario.ca/page/schedule-order-council-14482024