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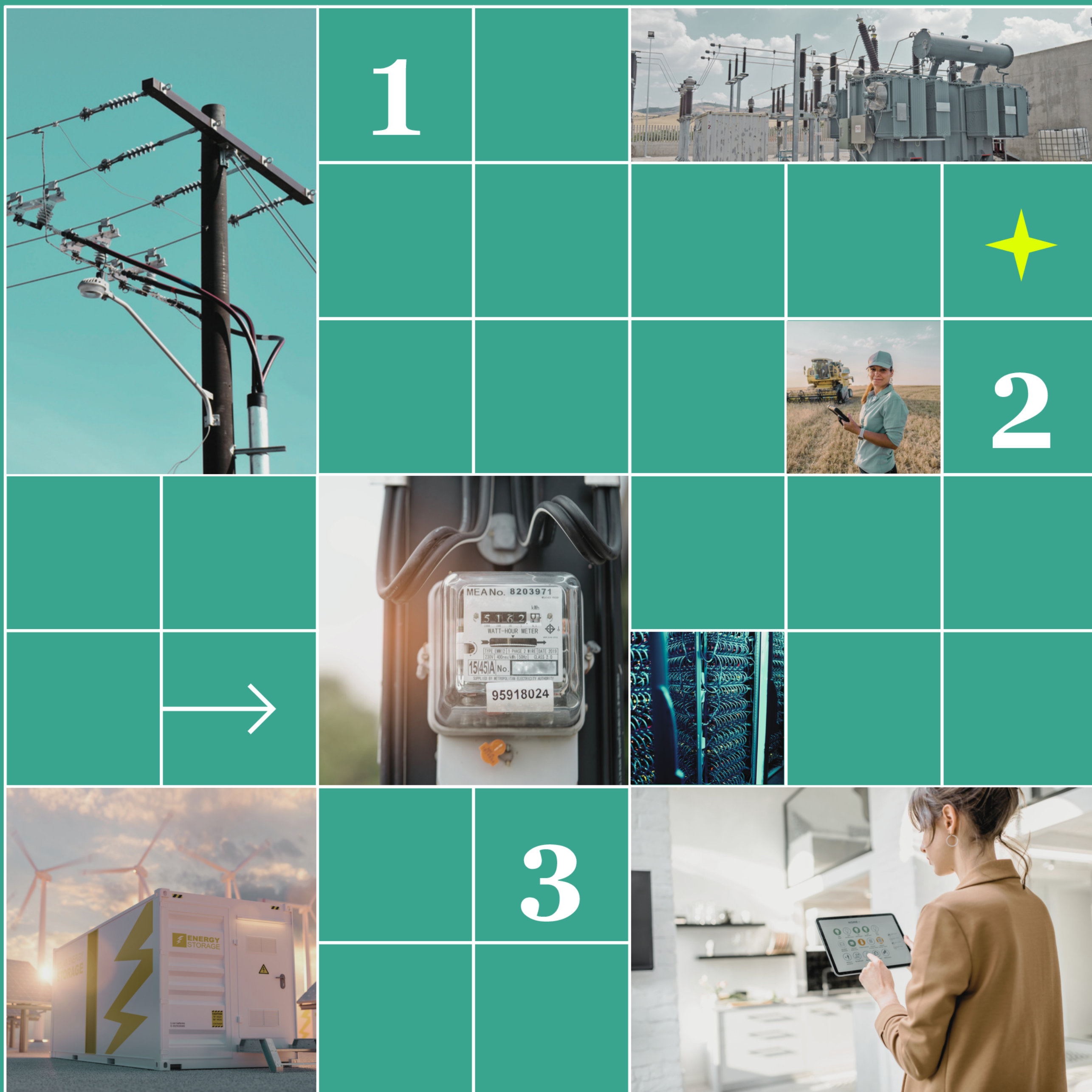

Optimizing Alberta's Electricity Distribution

3 Opening Moves and Next Steps for an Affordable, Reliable, Economy-Building Grid

Energy Futures Lab

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The Energy Futures Lab 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.

AUTHORS

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The Energy Futures Lab relies on the support of donors and corporate supporters who recognize the importance of leaning in to collaboratively explore, understand and solve systemic challenges in creating the Canadian energy system the future demands of us.

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Background

A system in flux

Alberta's electricity system is undergoing a massive transformation. Reshaping the sector is a confluence of developments driving electricity demand growth, including:

- **Emerging Industries** - expansion in energy-intensive industries like data centres, quantum computing, and hydrogen production[1].
- **Population Growth** - Alberta is one of Canada's fastest-growing provinces. In 2024, Alberta's population growth rate was 3.9% and close to double the national rate[2] resulting in higher than usual distribution connections. For example, in Calgary, residential distribution connections in 2024 were double the ten-year annual average.[3]
- **Electrification** - Core industries are increasingly electrifying processes to reduce emissions and improve efficiencies, and more homes and businesses are moving to integrate electric transportation and add cooling capacity to cope with warmer seasonal temperatures.[4]

At issue is the pace and scale of projected demand growth, and the province's ability to **maintain reliable and affordable service for customers** across the system as these pressures evolve. To date, meeting the province's growing demand was a fairly straightforward matter of increasing the capacity of centralized generation and connecting it to customers through the build-out of transmission and distribution infrastructure. To ensure the timely development of needed infrastructure, the system evolved to incentivize and prioritize capital investments by transmission and distribution companies (i.e. utilities). However, the pace and scale at which electricity infrastructure will need to be deployed to accommodate

[1] https://www.aeso.ca/assets/Uploads/grid/lto/2024/2024-LTO-Report-Final.pdf
[2] https://www.cbc.ca/news/canada/calgary/alberta-population-strong-slowing-1.7417039
[3] https://www.enmax.com/news/enmax-reports-financial-results-for-2024
[4] https://www.aeso.ca/future-of-electricity

electricity demand growth, shifting usage trends and customer needs is greater than anything the system has experienced.

While investments in generation and utility infrastructure will continue to be needed, **maintaining the current 'capital-investment-first' approach runs the risk of outstripping utilities' capacity to deliver needed infrastructure in time**, leading to increased disruptions to households and businesses. In addition, if utilities manage to keep pace with the current approach, it is likely to result in significant increases to customer electricity prices. This is particularly relevant in Alberta where nearly half of costs on residential electricity bills stem from transmission and distribution charges. **This is causing a deep and growing dissatisfaction among customers—people and businesses who already feel a lack of agency to materially affect their electricity costs—even as they increase efforts to make responsible choices.**

By customer we mean any 'end-user' or 'electricity user', including Industrial, Commercial, Residential, and Rural/Remote. We use the term customer (rather than end-user or rate-payer) as a reminder that this issue matters because it affects real people, their lives and livelihoods.

LEADING THE CHARGE: A VISION FOR ALBERTA'S ELECTRICITY FUTURE (2024)

The majority of customers in Alberta expect electricity to be available when they need it. Electricity is something that becomes top-of-mind when they receive their monthly bill or cause for concern when there is a power outage.

In recent years, dissatisfaction with year-over-year increases in electricity rates has led to more customers being interested in their electricity usage, and prompted them to invest in new technologies such as rooftop solar, combined heat and power, and electric vehicles as a means to increase autonomy and save costs.

Customer choice driving change

The distribution system is already evolving from single-direction to two-way electricity flows as a result of evolving customer choices. With customers demanding more from their electricity system, new generation sources are being connected directly to the distribution system. The number and types of electricity-consuming technologies being used to enhance optionality and flexibility for customers are also increasing. Importantly, these developments create demands and emerging economic activity the system was not originally designed to address. To ensure cost-effective and efficient service, utilities will need to implement new solutions to service new customers, manage intermittent generation, and address shifting loads in order to ensure optimization of the system. **Box 1 and Figure 2** define and illustrate such solutions, which are a combination of technologies and strategies used to enhance optimization, optionality and flexibility.

Definitions

Distributed Energy Resource (DER): Any technology connected to the distribution grid that affects the supply and/or demand of electricity, and generally fit into three categories: supply-side, demand-side, and energy storage.

Demand-Side Management (DSM): Strategies to influence customer electricity consumption, like energy efficiency and demand response.

Non-Wire Solutions (NWS): Solutions developed by utilities that use DERs or DSM to address system needs instead of traditional upgrades to the power grid.

Box 1: Definitions of Distributed Energy Resource (DER), Demand-Side Management and Non-Wires Solutions (NWS)

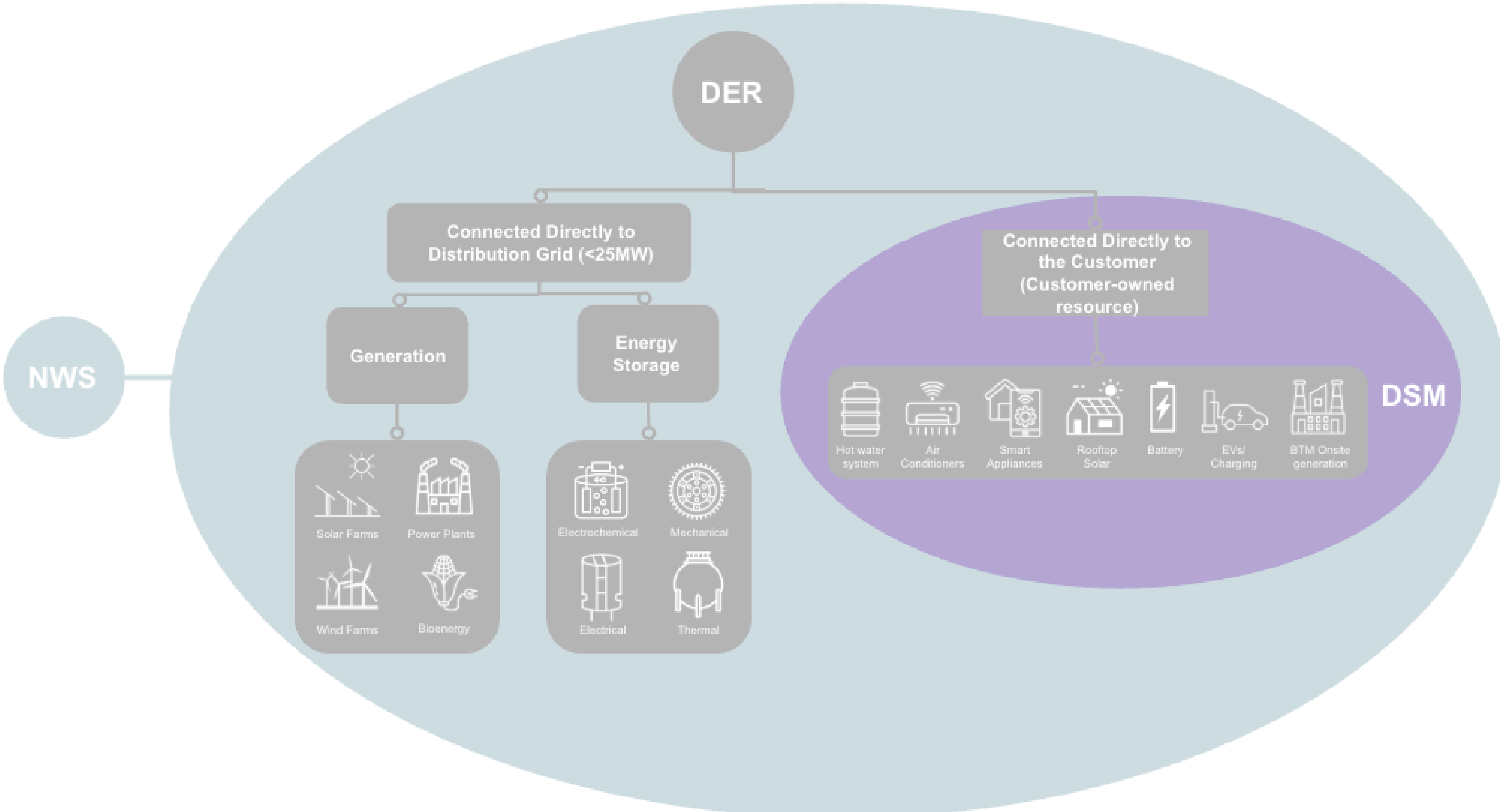

Figure 2: Illustration of the integration of DER, DSM and NWS

Growth at what cost?

To maintain Alberta's advantage, customers need a power system that encourages innovation to minimize electricity cost increases. To enable this, Alberta's regulatory framework must send the right signals to ensure utilities are adequately incentivized to invest in emerging, cost-effective, distribution-connected solutions that maintain reliability and address customer expectations.

Alberta's Performance-Based Regulation (PBR) model for distribution utilities aims to be a proxy for a competitive market by focusing on utility rates (prices) and quality of service while giving utilities the ability to manage costs over multiple years. PBR operates under a price cap approach (as opposed to a revenue cap approach), meaning that rates are adjusted using a formula that accounts for inflation and incentivizes efficiency to provide lower costs to customers, rather than setting a fixed amount of revenue a utility can collect. This structure is designed to provide utilities with flexibility to meet their system's needs while promoting cost efficiency and reliable service. To ensure customers benefit from utility efficiencies, PBR also has benefit-sharing provisions when utilities achieve greater revenues than anticipated.

While PBR was designed to allow utilities the flexibility of using capital and operating solutions to create efficiencies and meet customer needs, recent Alberta Utilities Commission (AUC) decisions to not approve utility plans that include solutions such as NWS and DSM illustrate the tension that exists between what is intended and what is being realized. Factors contributing to this may include:

- Utilities and regulators understand how to justify recovering costs from capital investments, whereas there is less direction for operational expenses, making them appear to be a riskier investment.
- Utilities forecast their capital investments and operating expenses to meet their load requirements for the PBR term (typically 5 years) based on historical data. Given the pace of change, this may not account for increasing demand growth, advancing technology, and rapidly shifting customer expectations.

In addition to utilities regulated by the AUC, municipal and co-op distribution utilities are facing challenges in securing the investments required to respond to the system's need for transformational change.

To ensure customers' electricity costs remain reasonable and the system continues to be cost-competitive, it is important that the intention of PBR is realized by enabling an expanded toolbox of distribution-connected solutions and that these tools fit within Alberta's deregulated market structure.

Driving Aligned Outcomes

The distribution system must adapt to the changing needs and expectations of electricity customers and the broader system. **To guide this journey, a distribution policy should outline a clear set of outcomes that the system must achieve** during this transformation, and, ultimately, work to enable new means by which distribution utilities can deliver optimal value to customers over time.

Our Ultimate Destination by 2050

> *A growing and carbon-neutral electricity system that enables greater customer choice and flexibility while maintaining safety, reliability and affordability.*

This statement is shorthand for AEF's vision for Alberta's electricity system, detailed in *Leading the Charge: A Vision for Alberta's Electricity Future*. This vision is further defined by a set of system-level shifts to reorient activity across the system over the coming decades:

- **Greater resilience** at local, regional, provincial, and national levels
- **Abundant and low-emissions electricity** sharpens provincial competitiveness, maintaining and attracting industry and jobs
- **Expanded customer products and services** empower customer choice and nurture new entrepreneurship and business models
- **Affordable, predictable costs** for all electricity system actors

The Next Waypoints: Outcomes Distribution Policy Should Unlock by 2030

Based on this vision, the following are the key, near-term outcomes a Distribution Policy should seek to enable within the next five years in order to meet evolving customer expectations.

These have been conceived as specific, measurable, achievable results of systemic action. While these can not be achieved without government action, they also can not be realized by government action alone—it will take system actors working together to bring these outcomes to fruition.

1. **Customers' electricity usage choices enable them to reduce the energy and wires costs on their electricity bills.**
2. **Customers are capable of being compensated or signaled appropriately for providing services to support bulk (transmission system) and local (distribution system) reliability.**
3. **Local reliability and community resilience to extreme events is enhanced through distribution-connected resources and regional connections.**
4. **Businesses are locating and investing in Alberta due to affordable electricity costs and reduced carbon intensity.**
5. **Utilities are increasingly using operational approaches, enabling utilities, retailers, and other competitive companies to create new electricity programs and service offerings that support optimization of the existing system and customer assets.**

New Capabilities Required

New Capabilities Required for the Distribution System to Achieve 2030 Outcomes

Achieving the desired outcomes will create new and enhanced customer experiences and stabilize overall system costs, as discussed in the following tables. To do this, a distribution policy must do more than address the immediate visible issues facing customers today. It must **enable capabilities for the entire system to function in new ways**. To create lasting solutions it must also prioritize additional goals (i.e. those outlined in the previous section) beyond those in place when the system was established.

We define a capability as that which creates the ability for any one or more electricity system actors (AUC, utilities, businesses, households, etc.) to contribute to the intended outcomes. Below, we identify three capabilities that should be prioritized as the government looks to evolve Alberta's distribution system. **Together they create the conditions to initiate, test, and accelerate new solutions that can support the electricity grid to address the increasing pace and scale of demand growth and changing customer needs.**

1. Integration of non-wires solutions into distribution planning to support optimization of utility assets
2. Expanded deployment of distribution-level demand side management (DSM) strategies through both regulated and market mechanisms to enhance customer engagement and participation
3. Real-time data collection, management and access to support system planning and empower customer choice

The three capabilities were chosen as they are compatible with or can be deployed through enhancements to the PBR and enable near-term benefits in addressing customer choice and affordability while establishing data frameworks and gathering the necessary data points to inform future action.

The following tables highlight each capability by describing:

- our recommendation for immediate actions policymakers can take to start the process of developing the identified capability as a feature of the distribution system and next steps
- how this capability benefits customers in Alberta,
- what is currently inhibiting this,
- and the implications or trade-offs to the broader system that may result from deploying it.

Capability #1

Integration of non-wires solutions into distribution planning

to support optimization of utility assets

Contributes to Outcomes: 2, 3, 4

Recommendations for Policymakers

OPENING MOVE:

Enable the AUC to work collaboratively to design and pilot supplemental mechanism(s) to PBR which will encourage utilities to plan for and optimize investments through non-wires solutions. The mechanism(s) should be designed and piloted:

→ In collaboration with customer groups, DER developers, aggregators, and the UCA, as well as distribution and transmission companies.

→ Within the current PBR term, to ensure it meets the intended outcome of creating greater system-level optimization before it is fully implemented.

→ To ensure non-wires solutions are considered as viable solutions, alongside capital investments.

→ To include triggers or indicators for what will warrant broader implementation.

RECOMMENDED NEXT MOVES:

- Enable the AUC to work collaboratively to design and pilot regulatory mechanisms that can appropriately signal utilities to use NWS to optimize service areas and the broader interconnected system. This should include:
  - Data collection and information access to understand current and emerging local constraints.
  - Coordinated planning between distribution and transmission companies geared towards overall system optimization.
  - Provisions for planning and procurement from customer-owned or third-party aggregator solutions to allow for both capital and operational solutions to be equally considered.
  - Updates to tariffs, as needed, to maintain fair and predictable rates.
- Update the mandate of the AUC, establishing a new approach that enables the consideration and weighting of economic, social, and environmental factors of projects. Such guidance will be key to support decisions that can deliver wider customer and system value.
- Investigate the longer-term opportunity to increase the tools for system optimization and alleviate local constraints by evaluating distribution-level services, such as voltage control, power factor, and power quality that some or all NWS could be used to manage. This may include future procurement of NWS through a fair, efficient and openly competitive market.

Benefits to Customers

Non-wires solutions may financially reward distribution-connected DER owners and customers for supporting system needs, while simultaneously reducing the carbon intensity of the broader electricity system. Specifically, customers:

- Who invest in DERs have the potential to earn revenue or reduce electricity bills when providing needed services to distribution companies.
- Experience lower costs and connection times due to a more efficient use of existing infrastructure.
- Experience stable prices as demand increases due to utilities having additional tools to optimize their system.
- Who live in under-served Indigenous and rural communities may experience better continuity of service, as well as generate additional revenue with targeted generation and storage investments sized to local needs.
- Who live in rural areas, can explore and advocate for benefits, beyond the tax base, from distribution-connected DER projects.

Inhibitors

- Utilities' current return-on-equity structure signals consideration of capital investment solutions, not a combination of capital and operational solutions.
- The AUC has no framework to assess a utility's investment in non-wires solutions to ensure a utility is utilizing the most optimal solution.
- Utilities cannot earn revenue when investing in customer-owned or third party solutions (i.e. contracting storage to operate during peak load or contingency scenarios.)
- Customer-owned or third party non-wires solutions have no price signals or distribution-level services to ensure these solutions provide benefit to the grid and not just generate system upgrade costs.

Implications

- New and existing DERs can now provide grid services instead of only requiring costly infrastructure upgrades.
- Having local constraints resolved by local resources may create more capacity throughout the system to support economic growth in existing and emerging industries.
- Careful design of NWS integration will be required to ensure such solutions are working to optimize the system as intended and costs are fairly allocated among customers.
- Coordinated and system-level planning between distribution and transmission companies will be critical to realize the full value of DERs.
- Reducing the pace at which distribution system capacity upgrades are needed may reduce or defer upstream transmission capacity upgrades resulting in less revenue for transmission companies.
- Optimizing the use of DERs and DSM strategies to manage local constraints will require a higher level of visibility and control for utilities. Key to this will be enabling comprehensive automation of real-time operations through digitalization of infrastructure and real-time data gathering.

Capability #2

Expanded deployment of distribution-level demand side management (DSM) strategies through both regulated and market mechanisms

to enhance customer engagement and participation

Contributes to Outcomes: 1, 2, 4, 5

Recommendations for Policymakers

OPENING MOVE:

Convene the distribution companies (investor-, municipal- and member-owned) to build shared principles and goals for demand response programs, as well as priorities for initial piloting and deployment. Identified program(s) should be:

→ Designed to create opportunities for the private sector to work with customers on delivering demand flexibility.

→ Designed with consideration of the unique attributes of various service territories and customer groups.

→ Designed as a tool to empower customer choice.

→ Where appropriate, designed in collaboration with customer groups, UCA, transmission companies, retailers and aggregators.

→ Designed and piloted to encourage participation from all customer groups so that households and businesses can receive fair compensation for choices they make.

→ Piloted to confirm value of wider-scale deployments and identify issues and potential solutions before broad program deployment, ensuring learnings have been shared with stakeholders.

RECOMMENDED NEXT MOVES:

- Enable the UCA to work collaboratively with customer groups, aggregators, distribution and transmission companies, retailers, and AUC to create a framework for integration of DSM in the province, including considerations for:
  - Data collection and information access to provide input into customer cost-benefit analysis and identify opportunities for efficiencies.
  - Clear definition of roles and authority for utilities, retailers, aggregators, provincial government, municipalities, and various customer types.
  - Program governance, fair cost recovery and alignment on affordability outcomes.
  - Rate structures and/or customer programming to provide appropriate signals for participation.
  - Appropriate signals for retailers, aggregators or other private sector companies to recruit customers in a way that creates a viable business model.
- Investigate the longer-term opportunity to increase the tools for system optimization and alleviate local constraints by evaluating distribution-level services (such as voltage control, power factor, and power quality) that some or all DSM strategies can support. This may include procurement through fair, efficient, and openly competitive markets.

Benefits to Customers

Participating in DSM programs can be straightforward and help all customers—from individual households to commercial buildings and large industrial facilities—reduce their electricity bills or create a new income stream. Importantly, it increases overall affordability for all customers, regardless of whether they directly participate. Specifically:

- DSM strategies or programs empower customers by providing greater control over electricity consumption and increasing benefits.
- Flexible commercial and industrial customers may generate a greater return on their operations by responding to price signals.
- Low income residential customers, unlikely to directly own DERs without financial assistance, can benefit from targeted programs that can alleviate high energy costs by helping reduce electricity usage or improve household efficiency.
- It is common for savings from DSM programs to be double the amount invested. Cost savings from DSM support economic competitiveness by lowering the cost of doing business and cost of living.

Inhibitors

- There is no direct incentive mechanism or signal for utilities, retailers or aggregators to deploy DSM strategies or programs enabling customer choice and benefits through energy efficiency, demand response or customer-connected DERs.
- Each distribution region in Alberta has different system designs, tools, resources, load profiles, and customer mix. This means the need to deploy DSM to meet local constraints and customer needs will likely vary between regions.

Implications

- Some DSM strategies, such as voluntary demand response programs, can be implemented without full advanced metering infrastructure (AMI) in place. However, to realize the full potential benefits of DSM, widespread AMI implementation will need to be established.
- AUC oversight may be required to ensure DSM programs have a suitable return on investment for all stakeholders.
- Using market mechanisms may increase participation in demand response programs. This should be considered as a longer-term opportunity with an objective to support stable overall delivered costs for customers across Alberta and not just in specific regions.
- To realize full DSM benefits, greater deployment of customer-connected DERs may need to be encouraged to to support both regulated programs and market mechanisms.
- Piloting of potential DSM programs is a crucial approach to gather additional information needed to fully understand system needs, tailor program design, and refine implementation before committing to a broader rollout.

Capability #3

Real-time data collection, management and access

to support system planning and empower customer choice

Contributes to Outcomes: 1, 2, 3, 5

Recommendations for Policymakers

OPENING MOVE:

Enable the Ministry of Affordability and Utilities to lead a collaborative effort to establish capability requirements and implementation timelines for utility AMI systems. This effort should include the following:

→ Engagement with consumer groups, UCA, distribution and transmission companies, retailers, aggregators, and AUC.

→ Development of consistent baseline capability requirements for utility AMI systems, including AMI, communications, billing systems, customer applications, etc. across all service areas.

→ Development of AMI deployment roadmap(s) and timelines for implementation within each service area.

RECOMMENDED NEXT MOVES:

- Develop a mechanism to enable all distribution companies (including investor-, municipal- and member-owned companies) to deploy AMI, communications, billing systems, customer applications to support delivering on an AMI deployment roadmap, ensuring all customers have access to the same level of service and programs.
- Establish protocols for governance on data management, sharing and interoperability between customers, utilities, retailers, and aggregators.
- Create a data platform to enhance data sharing between customers, DER developers, distribution and transmission companies, retailers, and aggregators. This may include consultation to understand stakeholder needs and required data and standards.
- Collaborate with customer groups, UCA, AUC, distribution and transmission companies to use existing data to determine what new rate structures could be developed to enable further cost savings for customers.

Benefits to Customers

Access to real-time customer data and information is foundational to fully realizing the benefits of NWS and DSM strategies. Furthermore, giving customers access to their own data empowers them to play a more active role in managing their electricity experience. Specifically, customers:

- May access a wider range of options to meet their electricity needs as utilities can use real-time data collection (AMI, GIS) and management systems (ADMS, DERMs) to increase DER integration.
- Can reduce their electricity bills when new rate structures (electricity and distribution rates) are deployed to signal adjustments to their usage habits.
- Have more options for actions to generate revenue or reduce costs as a result of increased competition through DER aggregation and customer participation in distribution-level markets.
- May experience enhanced reliability, including fewer or shorter power outages, as real-time data from AMI reduces utility response time to outages.

Inhibitors

- The collection, management, and use of customer usage data is limited by different infrastructure, communications, and billing systems across distribution companies.
- Data privacy concerns and access rules limit what can be shared between distribution companies, retailers, customers and third-party solution providers.

Implications

- AMI is needed to enable customers to receive full benefits from DERs being deployed to support NWS and DSM strategies.
- Investing in AMI systems and enabling their advanced functions and benefits may be in the order of hundreds of millions of dollars to deploy across the province. For these upgrades to be completed in a timely manner, additional funding mechanisms may be needed for smaller utilities.
- Customer usage data from utility AMI can be used by retailers and aggregators to create options for customers, but rates need to be aligned/coordinated between distributors and retailers to realize the potential for customer benefits and satisfaction. Any new rate structure needs to consider the unintended consequences of increased grid defection and shifting costs to customers who can not afford to invest in DERs.
- Advanced distribution-level data can support AESO load forecasting and reliability management by providing solutions to local constraints through the dispatch of local assets.
- Privacy concerns from customers must be addressed to enable monitoring, storing, using, and sharing user data.