

# Dispatchable Renewables and Energy Storage



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# 1. Executive summary

*The AESO has completed its assessment of the potential need for dispatchable renewables and energy storage, and developed a recommendation as Alberta transitions to a lower-emission electricity system.*

## 1.1 Government of Alberta request

The Climate Leadership Plan (CLP) announced in November 2015 seeks to transition Alberta away from carbon-intensive electricity generated by coal and toward lower-emission sources of electricity. In support of the CLP, the Government of Alberta is targeting 30 per cent renewable electricity generation by 2030 (the target).

On Nov. 29, 2017, the Government of Alberta requested that the AESO review electricity system reliability requirements to assess any potential need for dispatchable renewables and energy storage (DR&S) as significant intermittent generation is added to the grid to meet the target (see Appendix 1). This review was to include analysis and stakeholder engagement, and directed the AESO to provide a recommendation to the government on whether any additional products or services would be required. If there is a need, any AESO recommendations were to be consistent with contributing to meeting the Government of Alberta's renewable energy target, maintaining or improving reliability, be cost-effective, and ensure minimal market impacts.

The AESO has completed its DR&S review, including stakeholder engagement, a jurisdictional review, electric system reliability analysis, and cost/benefit analyses for various DR&S technologies, in order to meet the objectives of the government's request. The cost/benefit analysis did not consider potential economic development or other social benefits.

## 1.2 Stakeholder engagement

The AESO conducted an engagement process from February to March 2018. This involved reaching out to gather perspectives on DR&S from a broad range of stakeholders through the *AESO Stakeholder Newsletter*, via a questionnaire which was posted on the AESO website. A total of 88 stakeholders responded, and the AESO engaged directly in over 30 one-on-one discussions with a variety of these stakeholders, covering industry incumbents, various associations (e.g., the Canadian Geothermal Energy Association, Canadian Solar Industries Association, Canadian Wind Energy Association, Energy Storage Canada, Pembina Institute), customer groups (e.g., the Alberta Direct Connect Consumer Association, the Utilities Consumer Advocate, the Industrial Power Consumers Association of Alberta) and project developers of various DR&S technologies.

The comprehensive stakeholder feedback assisted in defining the DR&S review scope by recommending jurisdictions with higher renewable energy penetrations to learn from, recommending that a comparative cost/benefit analysis be performed, providing technology and project cost information to test cost assumptions incorporated in the analysis, and identifying various barriers to DR&S technologies entering the market which will be considered within future AESO action plans.

### 1.3 Jurisdictional review

The AESO engaged Energy + Environmental Economics, a leading industry expert, to conduct a global jurisdictional review in order to gain insights from other regions into typical challenges experienced due to increasing renewable energy penetration, and the approaches and methods used to help address these challenges. The review also explored any dispatchable resource and energy storage policies or mandates enabled by governments or system operators to assist with renewables integration. Fourteen different regions were selected, based on the regions having similar characteristics to Alberta. The regions included Australia, Chile, Germany, Ireland, Ontario, Spain, the United Kingdom, and several U.S. jurisdictions.

The jurisdictional review identified two common renewables integration challenges at higher renewable energy levels: the size and speed of system ramps due to higher variability of intermittent generation, and the volume of supply surplus situations due to high renewables generation during low customer demand periods. There were numerous flexibility options identified to address these common challenges, including selective curtailment of renewables in fast ramp and supply surplus situations, better use of existing supply resources and interties, improved forecasting and dispatching processes, and procuring additional flexibility in the market.

### 1.4 Assessing renewables integration requirements

The AESO performed a comprehensive reliability and flexibility analysis to determine the impact of integrating 30 per cent intermittent renewable into the power system by 2030. This included conducting power system and market studies based on the *AESO 2017 Long-term Transmission Plan* (LTP) and the *AESO 2017 Long-term Outlook* (LTO), respectively.

Two market simulation scenarios were studied to assess the future variability on the system as more intermittent renewables are integrated: a Moderate Coal-to-gas Conversion (2018–MCTG) scenario with 2,400 MW of existing coal converted to gas, and a High Coal-to-gas Conversion (2018–HCTG) scenario with 5,300 MW of existing coal converted to gas. The scenarios were modified from the LTO to incorporate higher wind generation, replacing some hydro and solar.

Various power system studies were performed to assess overall transmission reliability, including system adequacy, voltage and system stability, and system inertia. The results confirmed that there were no material challenges forecast. Current transmission development plans identified in the LTP will enable integration of the forecast level of renewables.

As expected, variability increases as additional intermittent wind generation is added to the grid. However, the increase in variability occurs at a slower rate than wind additions due to the forecast regional diversity of wind connecting across the province. The size and frequency of 2018 system ramps increase, with 10-minute ramp sizes doubling to the 300–400 MW range, and the 60-minute ramp sizes doubling to the 1,400–1,600 MW range in 2030.

Supply surplus situations are forecast to become slightly more frequent in the 2025 time period, but remain marginal at less than one per cent of total renewable generation through to 2030.

The current approach of procuring flexibility and ramping capability through the procurement of electricity in the energy market, and regulating reserves in the ancillary services market, is forecast to provide sufficient flexibility to meet the forecast increase in variability and ramping to 2030. Reliability performance metrics remain within threshold levels through to 2030. As such, the AESO does not see a requirement to procure any additional flexibility or ramping capability via dispatchable renewables at this time.



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## 1.5 Dispatchable renewables analysis

Although there is no emerging need to specifically procure additional flexibility on the system, the AESO assessed whether different types of dispatchable renewables could be more cost-effective in achieving the renewable energy target. The AESO performed a comparative analysis by replacing wind with different levels of run-of-river hydro, biomass and geothermal generation in the primarily wind-based 2018–MCTG case comparing market, Renewable Electricity Program (REP) and emissions costs.

The analysis forecasts an incremental total cost for all three types of dispatchable renewables: run-of-river hydro, biomass and geothermal. Wind energy is forecast to be the most cost-effective renewable energy resource. Cost reductions in other renewable technologies, such as solar, may change this in the future.

As a result of their higher capacity factor when compared to wind, proceeding with any REP-like procurement of dispatchable renewables increases the amount of capacity that is procured outside of the capacity market, which will have a further impact on that market.

## 1.6 Energy storage analysis

Energy storage is an emerging technology, with the exception of pumped hydro. Energy storage is becoming more prevalent in the electricity industry as renewable penetration targets continue to increase and technology cost curves continue to decline. Unlike dispatchable renewables generation, energy storage does not create “new” electricity. Energy storage technologies store previously-generated electricity by converting it through a charging process, holding the stored energy for a period of time, and then releasing the stored energy as electricity at a later time by discharging. Different energy storage technologies have different overall efficiencies when going through a charge–store–discharge cycle. No energy storage technology is currently 100 per cent efficient; therefore all are a net consumer of electricity as it moves through the cycle of charging–storing–discharging.

Although there is no emerging need to specifically procure additional flexibility on the system, the AESO assessed two different types of energy storage to determine its cost-effectiveness in Alberta’s electricity market. A short-duration, low-energy type using lithium-ion batteries, and a long-duration, high-energy type using pumped hydro, were assessed.

Short-duration, low-energy storage may be cost-effective in the electricity market as it can access sufficient revenues from the ancillary services market. The ancillary services market is small and will only support a small amount of energy storage before the market saturates and market prices decline. Long-duration, high-energy storage does not appear to be viable as future energy prices are not sufficiently volatile to enable access to enough revenues in the energy market to cover the higher costs. Proposed transmission tariffs increase energy storage costs materially if applied to the charging stage, and may need to be amended to recognize the unique aspects of energy storage systems.

## 1.7 Dispatchable renewables and energy storage definitions

The label “dispatchable renewables” applies to an asset that is both “dispatchable” and “renewable,” and both terms are defined within existing provincial legislation. “Renewable energy resource” is a defined term in the *Renewable Electricity Act* (REA) and “dispatch” is a defined term in the *Electric Utilities Act* (EUA).

While legislative changes may not necessarily be required to incorporate the concept of dispatchable renewables within Alberta’s existing regime, there may be a benefit to creating either a new definition or new term, depending on how these resources will participate in the future.

Energy storage is not currently defined in any Alberta legislation. A preliminary review of energy storage regulatory-related matters in Alberta reveals various approaches to defining energy storage by relating it to the existing *Hydro Electric Energy Act* (HEEA) or EUA in terms of generating unit, power plant, transmission facility, distribution facility, or load customer. An energy storage resource is unique in that it can “be like” all of these different types of assets (generation, transmission, distribution, load) at different times depending on the application of the energy storage resource. None of the above terms properly define energy storage resources.

Given the range of views within the industry as a whole and the challenges experienced across other jurisdictions in defining energy storage resources, the AESO proposes, within an Energy Storage Roadmap, to work with the various industry stakeholders to effectively define energy storage resource term(s) for Alberta and if needed, recommend changes to existing legislation and regulations.

## 1.8 AESO next steps

The AESO will develop an Integrated Flexibility Roadmap to provide a sustainable process to assess flexibility needs and to ensure sufficient flexibility to meet future needs as more intermittent renewable resources are added to the grid. The AESO will begin to engage industry stakeholders on the Integrated Flexibility Roadmap in 2019.

Numerous jurisdictions have developed energy storage roadmaps to proactively set a path within the industry for the evolving technology. The future for energy storage competitiveness is uncertain; however, industry around the world continues to invest in research and development to further reduce costs and improve capabilities, building significant momentum that is driving the technology forward. The AESO will develop an Energy Storage Roadmap to ensure that as technologies develop, barriers to integration are not created, and that tariff structures appropriately recognize the unique aspects of storage systems. The AESO will begin to engage industry stakeholders on the Energy Storage Roadmap in 2019.

If a grid-connected energy storage project was introduced in Alberta, it would enable a better understanding of this unique technology and how to integrate it within existing processes, market rules, industry regulations, and information technology systems.

Pending direction from the Government of Alberta, the AESO will engage stakeholders in the results of this report and its analysis, and seek feedback to incorporate into future analysis performed by the AESO as part of the Integrated Flexibility Roadmap and Energy Storage Roadmap.

## 1.9 Recommendation

The AESO’s analysis concluded that dispatchable renewables and storage are not needed for electricity system reliability as significant intermittent generation is brought onto the grid to meet the renewable energy target. The analysis indicated dispatchable renewables and storage were not as cost-effective as wind-generated renewable energy, based on current technology cost estimates. Based only on electricity system needs, the AESO does not recommend a specific procurement for dispatchable renewables and energy storage, at this time.

## 2. Introduction

*This report provides the AESO's assessment of the need for and potential benefits of dispatchable renewables and energy storage.*

### 2.1 Government of Alberta request

The Government of Alberta initiated its Climate Leadership Plan (CLP) in November 2015. The CLP focused on transitioning Alberta away from its traditional reliance on carbon-intensive generation of electricity through the accelerated phase-out of emissions from coal-fired electricity, and replacement of that generation with lower-emitting sources.

The AESO has developed and implemented the Renewable Electricity Program (REP) to procure 5,000 MW of utility-scale electricity generation from renewable energy sources by 2030. The first round of REP successfully concluded in December 2017, and two subsequent procurement rounds are currently underway.

On Nov. 29, 2017, the AESO received a letter from the Alberta Deputy Minister of Energy requesting the AESO to explore the potential role for dispatchable renewables and energy storage, as Alberta transitions to the renewable energy target.

The AESO was requested to evaluate the findings of the review, and to prepare a report and proposed next steps for consideration by the Government of Alberta by May 31, 2018, detailing the following:

- An assessment of whether additional products or services are required
- An assessment of whether such products or services may be procured via existing market mechanisms, or if discrete competitions would be necessary
- If deemed necessary, a proposal for the structuring and timing of any such discrete competitions for procurements
- A recommended definition for dispatchable renewables

If a need for discrete competition(s) is established, recommendations on competition design would follow by August 2018, with the subsequent competition(s) launched no later than November 2018, pending Ministerial approval.

### 2.2 About this report

This report provides the AESO's assessment of the need for and potential benefits of dispatchable renewables and energy storage, as Alberta transitions toward the renewable energy target. It is consistent with the four desired outcomes of the Government of Alberta:

- Contribute towards meeting the target of 30 per cent renewable electricity by 2030
- Maintain or improve the future reliability of the grid
- Ensure minimal market impacts
- Meet Alberta's electricity needs in a cost-effective manner



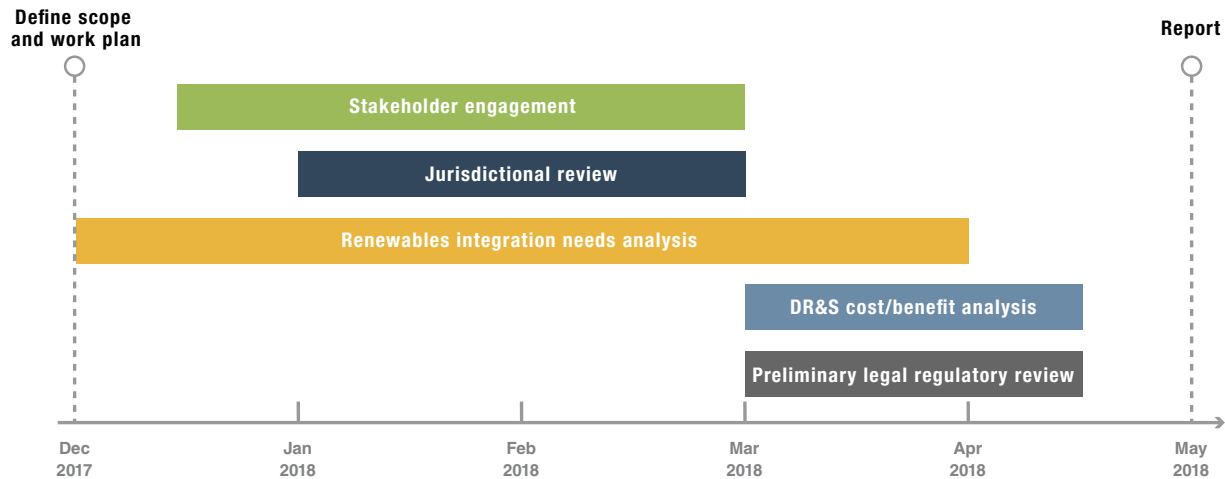
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In order to deliver a comprehensive report, the AESO initiated a compressed parallel work stream process.

The key work streams included:

- Stakeholder engagement:
  - To seek views on jurisdictions, integration needs, technologies, costs and benefits, and to inform the assessment performed in the other work streams
- Jurisdictional review:
  - To understand challenges and experiences from other regions progressing to higher renewables penetrations
  - To inform the integration needs analysis and cost/benefit analysis
- Renewables integration needs analysis:
  - To assess integration and reliability requirements as Alberta progresses towards the renewable energy target
  - To determine if any reliability or flexibility needs require action in the near term
- Dispatchable renewables cost/benefit analysis:
  - To directionally assess the cost-effectiveness of different dispatchable renewables technologies
- Energy storage cost/benefit analysis:
  - To directionally assess the cost-effectiveness of different energy storage technologies
- Preliminary legal and regulatory review:
  - To assess current definitions, regulations and legislation for dispatchable renewables and energy storage

**FIGURE 1: Key work streams**



The DR&S review examined the potential impacts of renewables integration as Alberta progresses toward the renewable energy target, with the majority of new renewable energy expected to be intermittent in nature. The report includes the AESO's results and proposed next steps, incorporating external industry experts and stakeholder feedback within the technical and cost/benefit analyses performed.

Section 3 of the report provides the results of a broad stakeholder engagement by the AESO to gain insights and perspectives that assisted in its review.

Section 4 of this report provides the results of a review of other jurisdictions with similar characteristics to Alberta's electricity system, undertaken to gain insights into the common challenges of extensive renewable energy penetration, and methods developed to address renewables integration.

Section 5 discusses the AESO's approach to assessing the Alberta electric system's future technical and flexibility requirements for renewables integration. The AESO summarizes its approach to meeting forecast flexibility needs, including a projection of reliability performance to 2030 as Alberta's generation supply mix changes and increased renewables enter the system.

Section 6 and Section 7 provide a cost/benefit assessment of various dispatchable renewables and energy storage technologies in the Alberta electricity market.

Section 8 reviews the current legal and regulatory landscape in terms of identifying potential changes to legislation, regulation, and ISO rules relating to dispatchable renewables and energy storage technologies.

Section 9 assembles the conclusions of the report, summarizes the next steps the AESO will pursue to manage flexibility requirements going forward, and provides the AESO's recommendation to the Government of Alberta.

Section 10 provides a number of reference items as appendices.

# 3. Stakeholder engagement

*The AESO engaged with a diverse range of stakeholders to gain valuable perspectives that helped inform the assessment.*

To assist the AESO in preparing this report, it began with broad stakeholder engagement to gain insights and perspectives that would help inform the process. A qualitative questionnaire was used to reach a variety of key audiences representing diverse stakeholder communities, as well as detailed, in-depth, one-on-one meetings with selected respondents.

## 3.1 Stakeholder questionnaire

The AESO stakeholder questionnaire (see Appendix 2) posed high-level queries that were intended to elicit a broad array of responses. It was designed to seek general inputs regarding the following subject areas:

- The need for DR&S now and as Alberta progresses toward the renewable energy target
- The role for DR&S in Alberta
- DR&S technologies to consider
- Barriers to developing DR&S in Alberta
- Pros/cons of DR&S development in Alberta
- Other jurisdictions to learn from

A total of 88 survey submissions were received from various stakeholders. Appendix 3 captures the multiple interests of stakeholders.

## 3.2 Direct engagement

The AESO also engaged in over 30 one-on-one discussions with various survey respondents to gain additional stakeholder insights, and sharing of more comprehensive information on economic factors associated with potential DR&S projects and economic projections of future costs for various DR&S technologies.

These survey respondents were selected based on the detail of their survey submissions, and to cover the breadth of stakeholder members, including industry incumbents, large developers, Indigenous representatives, and various other organizations (e.g., the Canadian Geothermal Energy Association, Canadian Solar Industries Association, Canadian Wind Energy Association, Energy Storage Canada, Pembina Institute), and customer groups (e.g., the Alberta Direct Connect Consumer Association, the Utilities Consumer Advocate, the Industrial Power Consumers Association of Alberta).



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### 3.3 Stakeholder insights

The comprehensive stakeholder feedback assisted in the AESO's review in several ways:

- Several stakeholders urged some form of comparative cost/benefit analysis be performed when considering different DR&S technologies, focused on the energy, capacity and ancillary services markets
- A variety of technology and project-related cost information was utilized to test the cost assumptions incorporated in the analysis
- A variety of barriers were identified which will be incorporated within future AESO action plans

The key feedback received from this stakeholder engagement is summarized below:

- DR&S resources can support the evolution to a lower-carbon grid
- DR&S resources can deliver a variety of flexibility capabilities that may be needed to address future intermittent renewable generation-related challenges
- Industry policy, rules and regulations should allow all technologies to be able to compete
- Wind and solar resources have flexibility capabilities that could be utilized more fully in the future
- Energy storage can provide a number of benefits, both as standalone assets or when paired with renewables
- Energy storage requires policy, rule and regulation changes to enable capturing the technology's numerous benefits
- Cost/benefit of DR&S should be evaluated before moving forward
- Market mechanisms should be used for enablement of any DR&S

The AESO takes no position on any of the feedback provided by respondents through this stakeholder engagement process.

## 4. Jurisdictional review

*A broad jurisdictional review yielded important insights about how different regions approached increasing renewable energy penetration.*

### 4.1 Scope of review

The AESO engaged Energy + Environmental Economics (E3), a San Francisco-based consulting firm with expertise in clean energy policy implementation, to perform a broad jurisdictional review. The review was designed to gain insights from other regions into typical challenges experienced due to increasing renewable energy penetration, the approaches and methods used to help address these challenges, and any dispatchable resource and energy storage policies or mandates enabled by governments or system operators to assist with renewables integration.

Fourteen different regions were selected for having similar characteristics to Alberta. The identified characteristics included regions with higher renewables penetrations and/or targets, a higher degree of intermittent renewable resources, a lower degree of hydro resources, a comparable level of interconnection to neighbouring regions, and a comparable generation supply mix, with pending or delivered coal phase-out. The jurisdictions reviewed were:

- AESO (Alberta Electric System Operator)
- Australia
- CAISO (California Independent System Operator)
- Chile
- ERCOT (Electric Reliability Council of Texas)
- Germany
- Hawaii
- Ireland
- MISO (Midcontinent Independent System Operator)
- NYISO (New York Independent System Operator)
- Ontario
- Spain
- SPP (Southwest Power Pool)
- United Kingdom

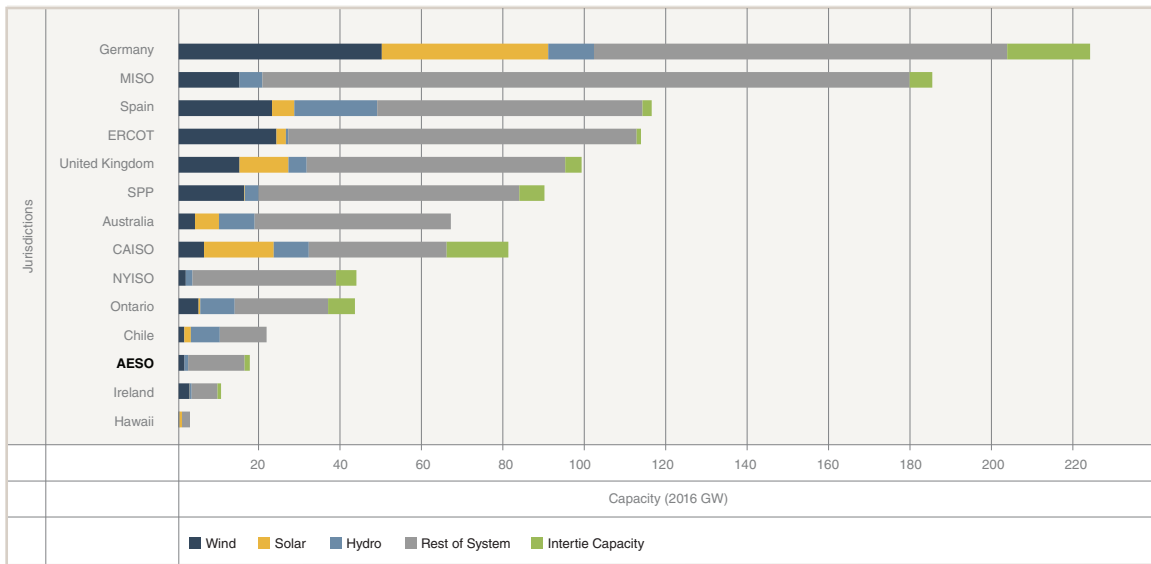
### 4.2 Renewable generation penetrations by region

Renewable energy levels, particularly if the renewable resources are intermittent in nature like wind and solar generation, is a key factor when assessing the integration of renewables. The grid-connected renewable generation penetration levels for the jurisdictions reviewed are illustrated in Figure 2A and Figure 2B.

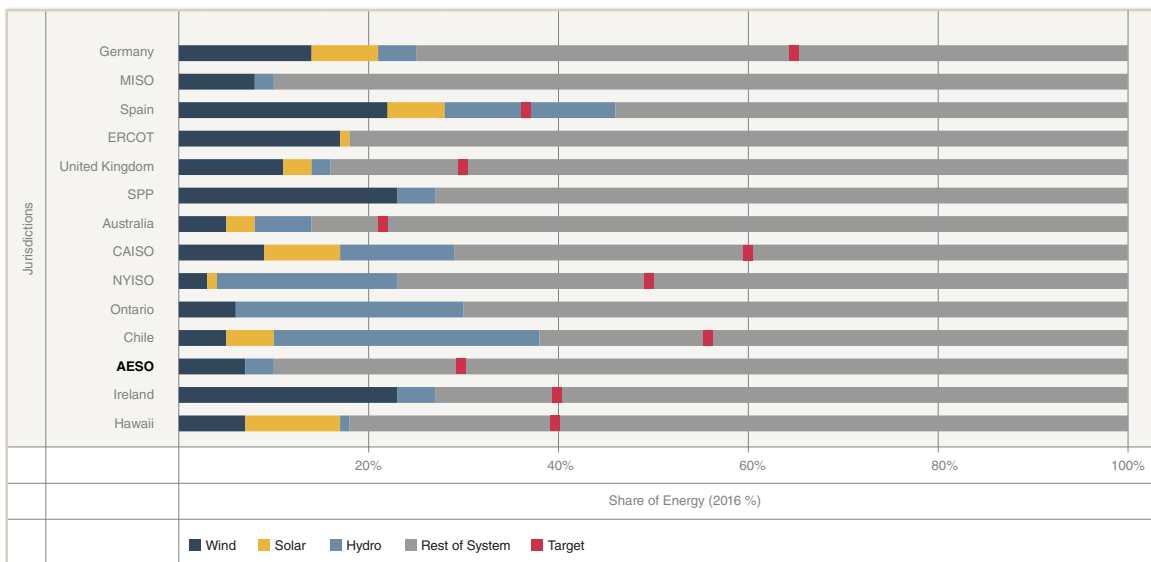
The red lines in Figure 2B represent the future renewable penetration targets for those jurisdictions, with hydro included for all regions for comparative purposes. Several jurisdictions are targeting future penetration levels in the 40–60 per cent range, such as Germany, CAISO, NYISO, Chile, Ireland, and Hawaii. Only Spain, Germany, CAISO and Ireland were nearing 30 per cent renewable energy from grid-connected solar and wind as of 2016.

The AESO will leverage related experiences and integration approaches from these leading renewable energy jurisdictions in developing the AESO’s next steps proposed in this report.

**FIGURE 2A: Renewable generation penetrations – by capacity**



**FIGURE 2B: Renewable generation penetrations – by share of energy**





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### 4.3 Other key renewables metrics

Beyond renewable energy penetration levels, the jurisdictional review identified other key renewables metrics across the regions that become more important as additional renewables are integrated into the grid.

These key renewables metrics (see Figure 3) provide a perspective on identifying the maximum renewable energy production in one particular hour, and the level of renewable energy curtailment during the year:

- Column D: maximum percentage of load being supplied by renewable energy in one hour in the year
- Column E: maximum MW of renewable energy supplied in one hour in the year
- Column F: maximum MW of renewable energy curtailed in one hour in the year
- Column G: percentage of intermittent renewable energy curtailed in a year

Some jurisdictions have had a single hour where renewable energy has supplied over 70 per cent of the customer load. Maximum renewable energy curtailments across these regions have ranged between 1,000–3,500 MW in one hour, with some jurisdictions incurring four per cent energy curtailment annually due to supply surplus situations. This informs the level of integration of renewables at the hourly level, and the corresponding level of curtailment being experienced to integrate renewables in some jurisdictions.

The size of interconnection capacity and current levels of energy storage provide a perspective on two infrastructure approaches that can provide flexibility on the grid.

- Column H: energy storage capacity on the grid, primarily pumped hydro built decades ago
- Column I: import/export capacity over interties with other jurisdictions

**FIGURE 3: Key renewable energy metrics for jurisdictions (as of end of 2016)**

Jurisdiction	Dominant renewable energy (RE) regime	RE % 2016 (2030 goal) and includes hydro	Peak hour RE share (% of load)	Peak hourly RE (MW)	Peak hourly curtailment (MW)	RE curtailment (% annual energy)	Storage (MW)	Import / export capacity (MW)
A	B	C	D	E	F	G	H	I
Germany	Wind and solar	29.5% (65%)	85%	55,000	1,580	1.2%	7,200	20,000
MISO	Wind	10% (n/a)	24%	13,600	~500–1,300	0.3%	2,530	14,000/8,000 w/ PJM* alone
Spain	Wind, increasingly solar	46% (35%)	~70%	17,000+	Unknown	5%	8,000	5,700
ERCOT	Wind	18% (n/a)	54%	17,400	1,000 MW	3–4%	70	1,100
United Kingdom	Wind	25% (n/a)	54%	19,300	Unknown	4.1%	2,900	4,000+
SPP	Wind	27% (n/a)	54%	12,078	2,000	<1%	475	1,200
Australia	Wind, behind-the-meter solar	16% (23.5%)	Unknown	Unknown	Unknown	Unknown	1,900	None
CAISO	Solar	36% (62%)	72%	15,000+	3,500	0.9%	4,200+	15,000
NYISO	Wind	23% (50%)	32%	7,700	Unknown	0.85%	2,240	5,000
Ontario	Hydro and wind	33.1% (n/a)	Unknown	Unknown	Unknown	5.66% Surplus baseload gen	224+	6,600+
Chile	Wind and solar	41% (48%)	31–42%	4,610	Unknown	>2%	60	200
<b>AESO</b>	Wind	8.4% (30%)	22%	1,600	Minimal	Minimal	0	1,650/1,475
Ireland	Wind	26% (40%)	~60%	2,815	~Est. 500 MW	3.2%	302	1,000
Hawaii	Behind-the-meter solar	25.8% (40%)	Oahu: 35% Maui: 72%	Unknown	Unknown	Oahu: 0.27% Maui: 5.5%	35+	None


\*Pennsylvania, New Jersey, Maryland Power Pool

#### 4.4 Options to address typical renewables integration challenges

As shown in Figure 4, the jurisdictional review identified various approaches that are available to address the two common renewables integration challenges: variability of intermittent generation resulting in ramping challenges, and generation supply surplus situations due to high intermittent generation during low customer demand periods.

There are various flexibility options available to address variability and supply surplus challenges. These options include better use of existing supply resources and inerties, selective curtailment of intermittent renewable energy, improved forecasting and dispatching processes, price signals to shift customer demand, and procuring new capabilities in the market.

**FIGURE 4: Flexibility options**



Type of Solution	Upward Dispatch Options (to serve load when wind ramps down quickly)	Downward Dispatch Options (to avoid curtailment if wind ramps up quickly)
<b>Regional Coordination</b>	Increased imports over existing inerties	Increased exports over existing inerties
<b>Load Adjustments</b>	Time-of-use rates to shift load away from high-need hours	Time-of-use rates to shift load toward high wind output hours (if predictable)
	Conventional demand response: load shedding/curtailment	Flexible loads; advanced: shaping load toward high wind/solar hours
<b>Renewable Generation Procurement and Dispatch</b>	Sub-hourly renewable dispatch: pre-curtailment lets thermal generation ramp up over longer horizon	Sub-hourly renewable dispatch: curtail; let renewables provide downward reserves
	Renewable portfolio diversity (by site location or technology): avoid curtailment by spreading renewable energy production over more hours	Renewable portfolio diversity: reduce size of ramps/forecast uncertainty by procuring renewables with less correlated output
<b>Conventional Resource Procurement and Dispatch</b>	Reserve products: market design to incent and hold fast-ramping generation	Market reserve products for flexibility: to provide planned downward ramp
	Additional hydro dispatch: or adjustments to make more flexible ramping	Additional hydro dispatch: or adjustments to reduce minimum level
	Flexible thermal resources: with faster ramp and start times	Flexible thermal resources: with faster start times and lower minimum output
<b>Storage Solutions</b>	Battery storage: if shorter-duration needed, or to provide reserves	Battery storage
	Pumped storage or compressed air energy storage (CAES): if long-duration needed	Pumped storage or CAES: if long-duration needed for significant curtailment

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## 4.5 Jurisdictional review summary

Key observations gained from the jurisdictional review include the following:

- Renewables integration challenges vary by jurisdiction, due to regional system characteristics such as supply mix, inertia capabilities, and system size, as well as the type and level of renewable generation
- The two common integration challenges experienced are the size/speed of variable generation-related supply ramps for wind and solar, and the volume of generation during supply surplus situations, particularly at those times when intermittent renewable generation is high and customer demand is low
- Approaches to addressing renewables integration challenges in one jurisdiction need to be properly assessed for their applicability and effectiveness within Alberta
- There are numerous flexibility options available to address the common integration challenges
- Selective curtailment of renewable electricity is an important approach to leveraging the capability of renewables assets and addressing potential integration challenges
- Energy storage is an emerging technology, with several potential benefits that could assist with renewables integration challenges

The jurisdictional review report can be found in Appendix 4. The report provides details for each jurisdiction in addition to summary information.

# 5. Assessing reliability and renewables integration

*The AESO assessed whether the overall transmission system would remain reliable as Alberta transitions away from coal generation and integrates 30 per cent renewables by 2030.*

## 5.1 Primary integration challenge areas

A key step in the DR&S review was to assess the primary integration challenge areas (see Appendix 5) Alberta may experience as it progresses towards integrating 30 per cent renewable energy by 2030, renewables which are expected to be primarily intermittent in nature.

As more variable intermittent generation is added to the system, the AESO must match the changing net demand on the system with dispatchable resources, every second of every day, to reliably meet customers' ever-changing electricity needs.

Net demand is equal to the overall customer demand, less the overall variable generation on the system at every moment.

The challenge to match dispatchable resources to a more variable net demand increases as more intermittent generation is added to the system.

As indicated in the jurisdictional review, Alberta's two renewables integration challenge areas will be:

- Having sufficient flexibility in dispatchable resources to be capable of matching the speed and size of net demand changes, every second of every day
- Having sufficient flexibility in dispatchable resources to reduce the curtailment of generation surpluses to acceptable levels

In addition, the AESO assessed whether the overall transmission system would remain reliable as Alberta transitions away from coal generation and integrates renewables to meet the 2030 target.

### 5.1.1 Variability and flexibility

Dispatchable resources have different degrees of flexibility. Flexibility includes attributes like the speed to which the resource can change output up or down (ramp rate), the minimum level of output the resource can operate at (minimum stable output), the time a resource requires to remain online before being dispatched offline (minimum run time), and the time a resource requires to come online after being offline (minimum start time). The AESO system controllers need to know these various attributes for all dispatchable and variable resources to be able to effectively meet changing net demand requirements.

The combination of the entire fleet's flexibility will change as the supply mix evolves over the long term. The overall fleet needs to be sufficiently flexible to meet the variability in net demand on the system while maintaining required reliability performance metrics.

## 5.2 Transmission reliability and flexibility assessed

### 5.2.1 Transmission reliability assessed

The AESO assessed the following power system parameters to determine whether any material transmission reliability concerns or challenges are expected as Alberta progresses towards the target.

- Transmission system adequacy
  - Is the system able to reliably transfer generation from source to loads without transmission element overloads or excessive voltage disturbances occurring?
- Voltage and transient stability
  - Is the system able to withstand a major disturbance and remain stable?
- System inertia
  - Will the system have enough inertia to ensure frequency remains stable following a major disturbance, to start large motors and meet HVDC system requirements?
  - Will enough short-circuit capability be available to ensure system protection operates as required?

The current plans identified within the *AESO 2017 Long-term Transmission Plan* will enable sufficient transmission system adequacy. The AESO also performed various technical studies to assess voltage and transient stability and system inertia. The study results confirmed directionally that there were no material challenges forecast as Alberta transitions to the renewable energy target.

The AESO, in its normal course, will continue to perform similar reviews in the future to reaffirm these results, particularly as new generation supply information becomes available and as the future integration of renewable energy progresses onto the system.

### 5.2.2 System flexibility: parameters assessed

The AESO assessed the following system flexibility parameters in order to determine whether any material renewables integration concerns or challenges are expected in system flexibility as Alberta progresses towards 30 per cent renewable energy by 2030.

- System variability and ramping capability
  - What will the future net demand ramping requirements potentially be?
  - Will the dispatchable resources available in the market be able to be dispatched up or down fast enough to meet changing variability on the system?
  - Do we have sufficient flexibility to meet our reliability performance obligations, particularly with the Western Electricity Coordinating Council?
- Supply surplus
  - Are the dispatchable resources able to be dispatched down fast enough and low enough to have acceptable levels of curtailed surplus generation during periods of high renewable generation and low customer demand?

### 5.2.3 System flexibility: assessment approach

In order to assess future flexibility needs, the AESO updated the LTO Reference Case with more recent information, and replaced the hydro and solar additions with wind additions since wind is currently the most variable renewable energy resource. Should other renewable resources such as solar come onto the grid, these resources are expected to reduce variability on the system. The new scenario is referred to as the 2018 Moderate Coal-to-gas (2018–MCTG) scenario throughout this report. The 2018–MCTG scenario achieves 30 per cent renewable energy by 2030, and with wind generation as the primary renewable resource, provides the highest level of intermittent renewable generation and therefore the highest level of variability against which to assess future flexibility requirements. The LTO High Coal-to-gas scenario was similarly updated to create a 2018–HCTG scenario, which was used for sensitivity analysis purposes (see Figure 5).

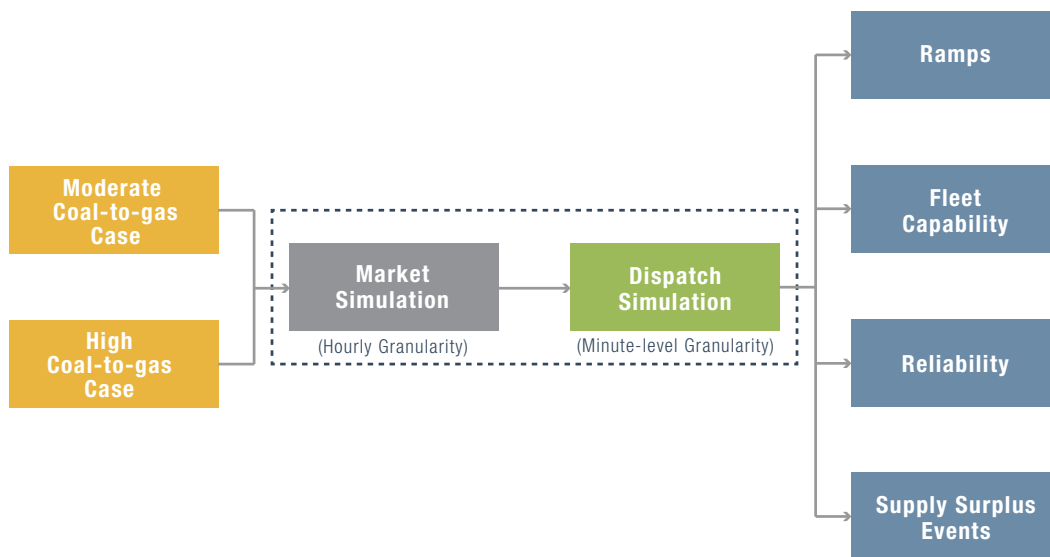


The 2018–MCTG case assumes 2,400 MW of the existing coal fleet converts to gas, which has similar flexibility to coal. The remaining coal fleet assets would retire, resulting in additional simple-cycle and combined-cycle gas facilities being developed, thereby increasing the fleet’s overall flexibility.

The 2018–HCTG case assumes 5,300 MW of the existing coal fleet converts to gas. Since the majority of coal converts to gas—having similar flexibility to coal—there are fewer additional simple-cycle and combined-cycle gas facilities developed, and therefore less overall fleet flexibility when compared to the 2018-MCTG case.

The two scenarios were modelled through a market simulation tool to create hourly profiles spanning the 2018–2030 timeframe. These hourly profile cases were then further modelled through a dispatch simulation tool to create minute-level profiles to assess ramping requirements, and to assess how the fleet would respond to dispatches necessary to match the forecast net demand variability.

**FIGURE 5: System flexibility – assessment approach**

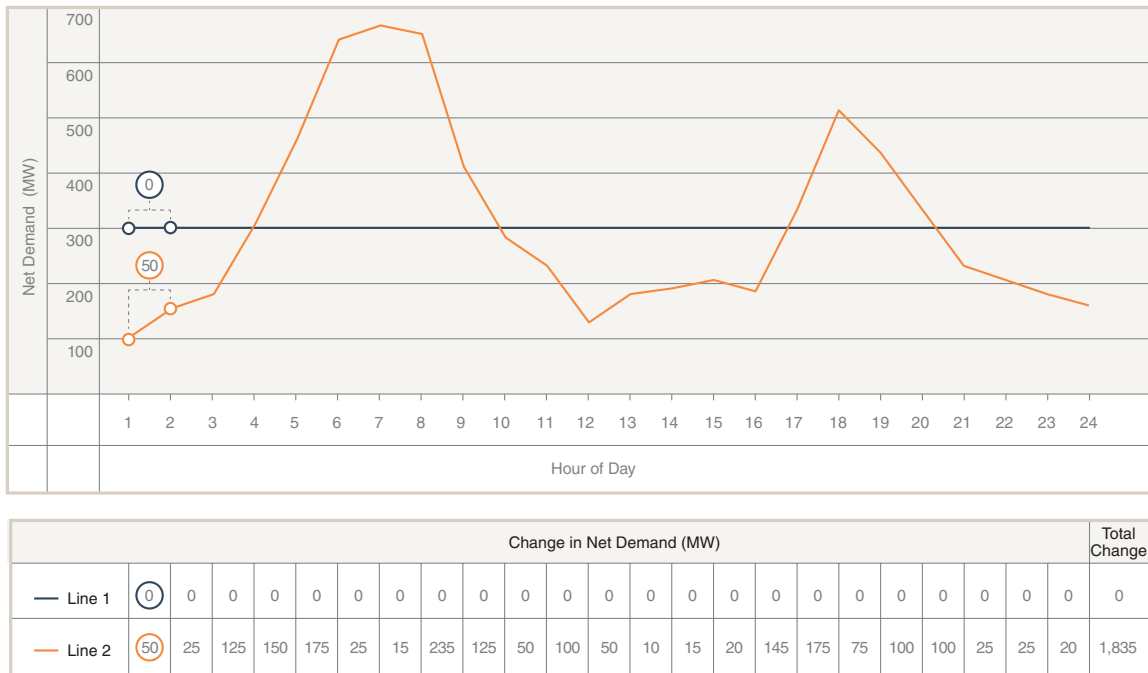


### 5.2.4 Measuring net demand variability (NDV)

One key metric to measure the degree of variability on a system is the cumulative change in net demand over time. The greater the change in net demand over time, the greater the variability on the system.

Figure 6 illustrates the concept of net demand variability (NDV). The graph illustrates two different net demand curves for a day. The cumulative change (absolute) during the day for Line 1 is zero; it has no net demand variability. The cumulative change for Line 2 during the day is 1,835. Line 2 is clearly more variable than Line 1. The greater the change in net demand, the greater the variability.

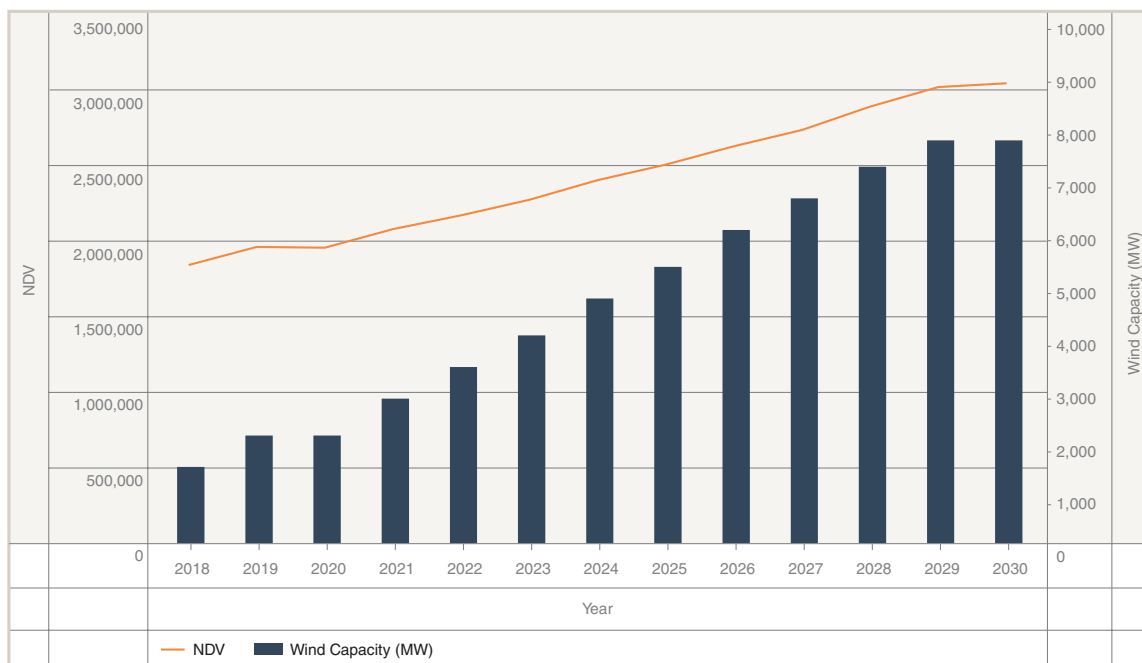
**FIGURE 6: Illustration of NDV**



### 5.2.5 NDV increases with increasing intermittent renewables

As shown in Figure 7, the forecast of NDV increases from 2018 to 2030 as additional variable generation is added to the grid. The rate of NDV increase is less than the rate of wind additions to the grid. This is due to the regional diversity of new wind sites being located across the province in different wind resource zones.

**FIGURE 7: NDV forecast for 2018–2030 timeframe**

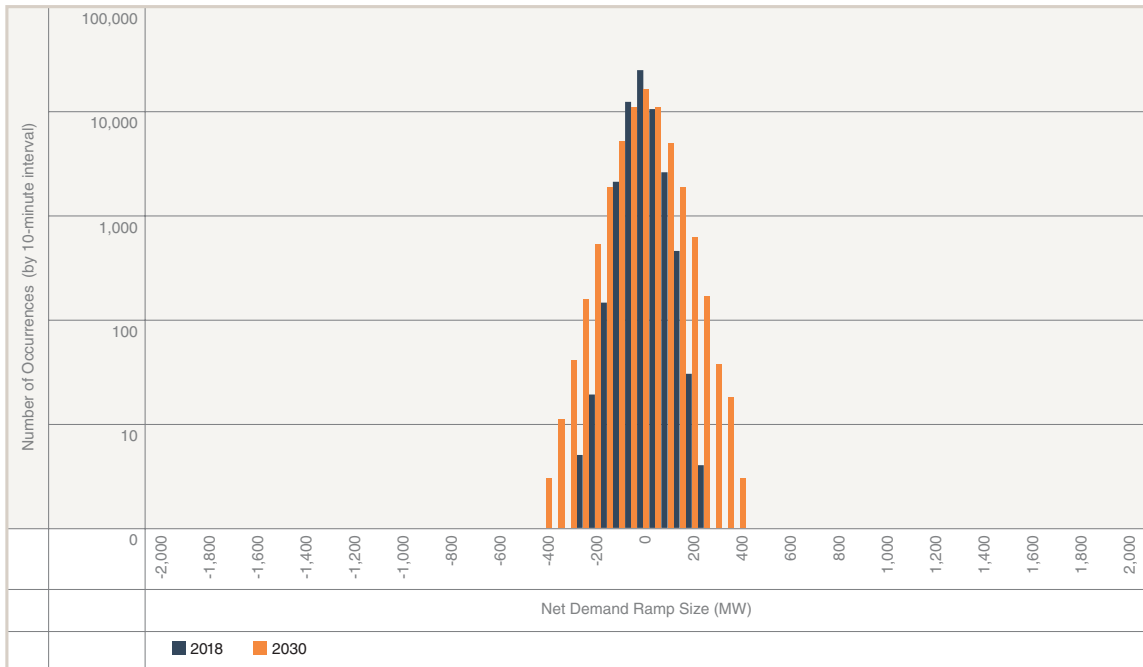


### 5.2.6 Net demand ramp size/frequency impacts

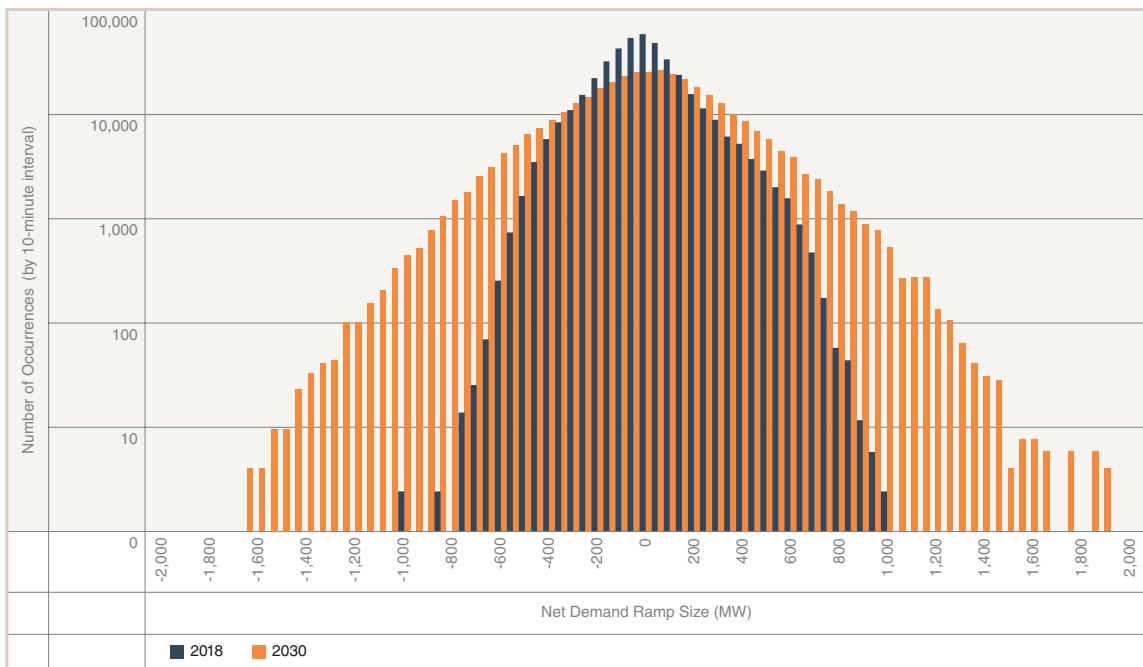
The size and frequency of net demand ramps on the grid are one of the common challenges experienced in jurisdictions with higher intermittent renewables penetrations. Dispatchable resources need to be able to match the size, speed and frequency of the net demand ramps in order to reliably supply customers as additional intermittent renewable generation is added to the grid.

Figure 8A and Figure 8B provide the frequency by net demand ramp size for two different timeframes. The 10-minute time frame in Figure 8A is generally associated with the regulating reserve market timeframe, while the 60-minute timeframe in Figure 8B is generally associated with the energy market timeframe. As can be seen in Figure 8A, comparing 2030 forecast 10-minute ramp sizes to 2018, ramp sizes increase to the 300–400 MW range. In Figure 8B, comparing 2030 forecast 60-minute ramp sizes to 2018, ramp sizes double from the 700–800 MW range to the 1,400–1,600 MW range. Additionally, the frequency of larger hourly ramps increases in 2030. As such, as more intermittent renewables are added to the grid, net demand ramps will increase in size and frequency.

**FIGURE 8A: 10-minute net demand ramp forecast**



**FIGURE 8B: 60-minute net demand ramp forecast**



The AESO utilized the NDV analysis to determine whether the energy market and regulating reserve market would continue to be effective in meeting reliability performance requirements with 30 per cent renewables by 2030.

Section 5.3 summarizes these results.

### 5.3 Addressing flexibility and reliability needs

The AESO currently uses several approaches to address the flexibility needs on the system, matching net demand with dispatchable resources.

The three primary approaches are:

- Dispatching the energy market up or down the merit order to meet the energy and ramping needs of net demand
- Regulating reserves ramp up or down, via automatic control, in order to meet the residual net demand needs that are not met by ramping the energy market merit order
- Wind power management, which curtails wind generation during fast, large up-ramp events, if necessary

Currently, the AESO does not require or procure a specific or separate flexibility or ramping product in the market. It procures flexibility and ramping capability through procurement of energy in the energy market and procurement of regulating reserves in the ancillary services market. The AESO relies upon system controller experience and dispatch tools to manage the minute-by-minute dispatchable resources needed on the system to supply the net demand.

For the 2018–MCTG scenario, the AESO simulated dispatching the energy market and regulating reserve market up-and-down to meet the forecast net demand. On average, the energy market provided 70 per cent of the ramping requirements and the regulating reserve market provided the remaining 30 per cent in order to meet the NDV on the system and deliver acceptable reliability performance.

In order to ensure acceptable reliability performance on the system and to assess whether sufficient system flexibility exists to address NDV, the AESO monitors three key reliability performance metrics.

The three reliability performance metrics are:

- Interchange System Operation Limit (SOL) Violation – real-time violations are not acceptable, while simulated future results of less than five events per year can be proactively mitigated to not occur
- Control Performance Standard #2 (CPS2) Violation – needs to remain above 90 per cent
- Large Area Control Error (ACE) Event – a proactive indicator, not a violation as a growing number of large ACE events typically increases the risk of having a future SOL violation.

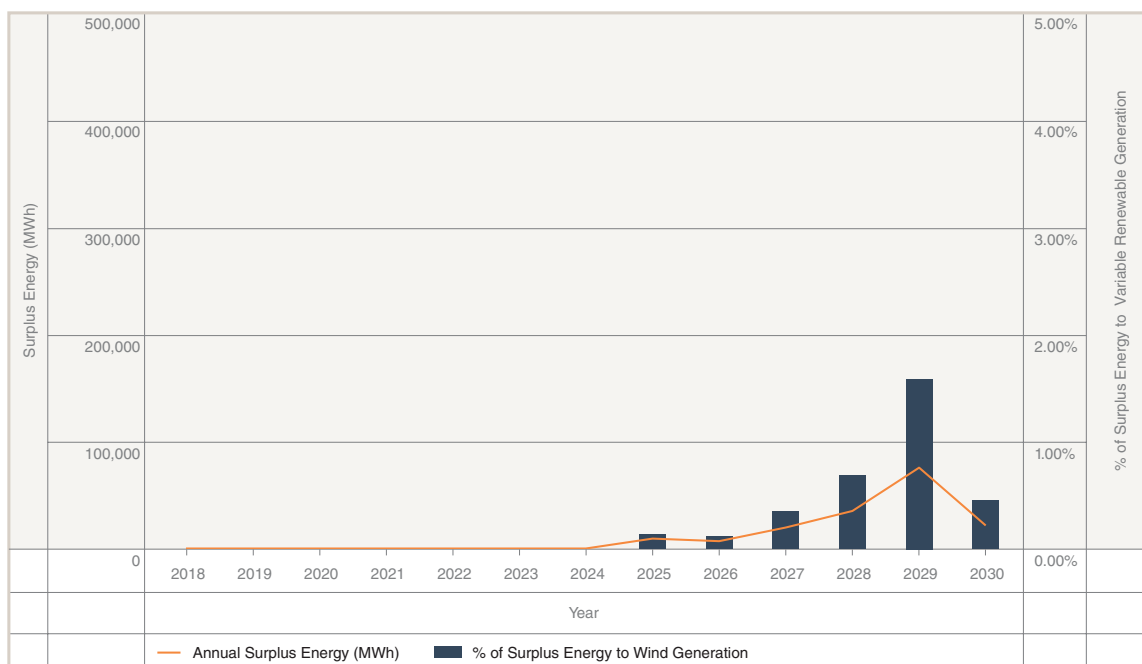
Figure 9 summarizes the reliability performance metric results for the 2018–MCTG and 2018–HCTG scenarios. All reliability performance metrics are within acceptable ranges. Since the key reliability performance metrics are forecast to remain within acceptable ranges, the energy market combined with the regulating reserve market delivers the needed flexibility to 2030. No additional flexibility resources are forecast to be required at this time.

**FIGURE 9: Reliability performance metrics**

Year	2018–MCTG			2018–HCTG		
	CPS2 (>90)	SOL (<5)	Large ACE (proactive indicator)	CPS2 (>90)	SOL (<5)	Large ACE (proactive indicator)
2018	99.9	0	0	99.9	0	0
2019	99.8	0	1	99.8	0	0
2020	99.8	0	1	99.8	0	1
2021	99.7	0	1	99.7	0	1
2022	99.6	0	1	99.5	0	3
2023	99.7	0	0	99.6	0	3
2024	99.7	0	3	99.5	1	2
2025	99.5	0	5	99.4	0	5
2026	99.4	1	10	99.2	1	8
2027	99.5	0	5	99.3	2	13
2028	99.3	1	11	99	0	18
2029	99.1	1	7	98.9	1	17
2030	98.5	1	6	99.1	0	9

## 5.4 Impact of increased renewables on supply surplus

**FIGURE 10: Generation supply surplus forecast**



Supply surplus events occur when generation exceeds demand and all dispatchable generation has been reduced to minimum stable levels. In those situations, supply is surplus to net demand requirements, and generation will need to be curtailed. This may result in increased on/off cycling of generating assets in the future, and corresponding wear and tear impact on those generating assets that experience increased cycling. Supply surplus events are forecast to marginally increase in frequency and size as additional intermittent generation is added to the system. These events occur more frequently during low customer demand periods and high variable generation periods.

Figure 10 provides the forecast of supply surplus energy by year to 2030 for the 2018–MCTG. This forecast does not incorporate any measures to curtail variable generation, which is a flexibility option jurisdictions use to manage the size and frequency of supply surplus situations.

The AESO forecasts a marginal level of potential supply surplus situations with less than one per cent annual surplus energy as a percentage of wind energy output by 2030. Supply surplus situations could be beneficial to long-duration, high-energy storage technologies, as these technologies could store this surplus energy and discharge the energy at a later time. However, the levels in Alberta are forecast to be marginal to 2030.

A key assumption in this analysis is that the interties with other jurisdictions are available at their full transfer capability for exporting excess generation. A lower level of intertie transfer capability will result in higher supply surplus forecasts. Further scenarios will be assessed in future flexibility studies (see Section 9.1) to consider possible ranges in supply surplus situations.



## **5.5 Conclusion: no emerging reliability need to procure additional system flexibility**

The AESO's flexibility analysis was based on scenarios that achieved the renewable energy target. The analysis revealed the following key results:

- No emerging reliability need exists to specifically procure or enable additional flexibility into the system
- Flexibility needs are connected to the timing of additional intermittent renewable generation
- The energy and regulating reserve markets are expected to provide sufficient flexibility to reliably deliver on the forecast variability to 2030 with 30 per cent renewables penetration
- Supply surplus generation is forecast to be marginal at less than one per cent of variable generation with a potential increase in generation on/off cycling
- As no procurement for flexibility is required, there will be minimal market impacts or incremental costs incurred outside of the market to meet future flexibility needs

### **5.5.1 Integrated Flexibility Roadmap**

The AESO will be initiating an Integrated Flexibility Roadmap to effectively manage flexibility in the future. The roadmap will assist in managing flexibility related to the evolving generation supply mix, the introduction of a capacity market, the increasing level of intermittent generation, and the growing interest across the industry in system variability and flexibility.

The AESO considers this work as its normal course of business and will continue to progress work over the next few years in the area of flexibility forecasting and management. The AESO will include industry feedback on the roadmap's development and share results with the industry through its public reporting processes. As described in Figure 4 on page 15 (Sec. 4.4), there are numerous flexibility approaches that can be proactively considered if future analysis forecasts growing reliability performance metric concerns.

The objectives of the Integrated Flexibility Roadmap will be to:

- Sustain the flexibility modelling process to forecast future flexibility needs and capabilities
- Refine the modelling process with calibration from actual results
- Proactively plan to incrementally enhance system flexibility through cost-effective approaches, should additional flexibility be required in the future

# 6. Dispatchable renewables analysis

*The AESO assessed the cost-effectiveness of three different dispatchable renewables technologies relative to intermittent renewable wind energy.*

## 6.1 Cost-effectiveness of procuring dispatchable renewables

In assessing the benefits of dispatchable renewables, since there is no emerging need to specifically procure additional flexibility for the system, the benefit question becomes whether different dispatchable renewables can competitively replace the expected wind-based renewable energy procured through the REP. If the dispatchable renewables are more cost-effective, overall costs to customers will be reduced and the NDV will be reduced on the system due to less intermittent wind.

The levelized cost of energy (LCOE) in \$/MWh produced from dispatchable renewables is a key factor in comparing how competitive a renewable resource will be to wind. Levelized costs include all costs to produce energy and cover variable operating costs, fixed costs, and financing costs. The higher the capacity factor of the dispatchable renewable resource, the greater the energy produced per megawatt of capacity and the lower the LCOE.

### 6.1.1 Dispatchable renewables technologies assessed

The AESO assessed three different dispatchable renewables technologies (see Appendix 5) in this report: run-of-river hydro, biomass, and geothermal generation. Definitions of DR&S are described in Section 8.

#### **Run-of-river hydro**

Run-of-river hydro generation produces electricity from river flows with minimal dam construction and therefore no material water storage capability. The generation produced follows the river flow levels, daily and seasonally, with maximum production during the freshet season. Consequently, capacity factors of run-of-river projects can vary greatly depending on individual project siting and environmental characteristics. Run-of-river hydro may have flexibility to ramp up or down generation, within the constraints of maintaining the regulated river flows and utilizing any short-term storage.

Run-of-river hydro generation projects are typically smaller in size when compared to dam hydro projects, as dam construction tends to be the more complex, risky and costly part of a hydro project. The smaller size for run-of-river hydro typically results in lower transmission costs to interconnect the project. Depending on the site location, run-of-river hydro can benefit from upstream dam hydro projects that already regulate the river flows downstream to the site, improving overall consistency of flows daily and seasonally and increasing the capacity factor of the run-of-river hydro site. There is currently approximately 420 MW of run-of-river hydro capacity in Alberta.

#### **Biomass**

Biomass generation produces electricity from biomass products such as forestry waste, municipal lumber waste, or grain straw. Biomass plants are typically smaller in size, in the range of 10–50 MW. This is primarily because the plants are sized to the fuel resource within a region, as transportation of the fuel source is a material cost. Energy is produced by burning the biomass through a boiler system, which results in similar flexibility to ramp up or down as a coal-fired generation plant. Biomass plants prefer to operate at stable output in the higher output range as this is the most efficient point of operation. There is currently approximately 370 MW of biomass capacity in Alberta.

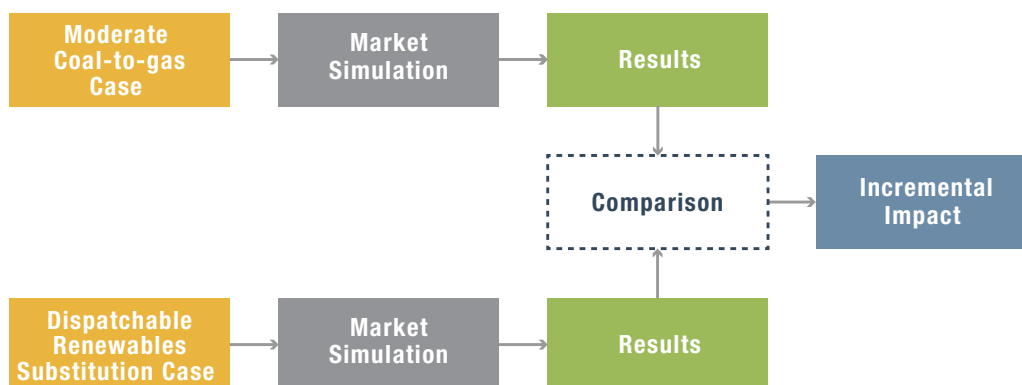
## Geothermal

Geothermal generation produces electricity from the heat below the surface of the ground. Different regions have higher heat gradients below the surface at different depths. Wells are drilled to depths in the kilometre range in order to access sufficient heat gradients. The cost of drilling the wells is a material cost in geothermal electricity production. Volcanic regions like Iceland and regions with major hot springs like California are more suited to geothermal electricity production. There are currently no geothermal electricity generation plants in Alberta, with the first geothermal heating pilot project being advanced in the Hinton region. Geothermal plants prefer to operate at stable output in the higher output range, as this is the most efficient point of operation.

### 6.1.2 Comparative scenario analysis

In order to provide directional results on the net cost or net benefit of various types of dispatchable renewables in the market, the 2018–MCTG scenario was used to represent future market conditions to 2030. Different “substitution cases” for three dispatchable renewable technologies (biomass, geothermal and run-of-river hydro) were substituted into the 2018–MCTG scenario by replacing wind resources, ensuring to match renewable energy totals to maintain the renewable energy target (see Figure 11). Nine different substitution cases were simulated (see Figure 12) in order to determine if different capacity levels of dispatchable renewables had different cost/benefit results. In the simulations, all dispatchable renewable energy is bid into the energy market at zero dollars, essentially as a price taker, similar to wind today.

**FIGURE 11: Comparative scenario analysis approach**



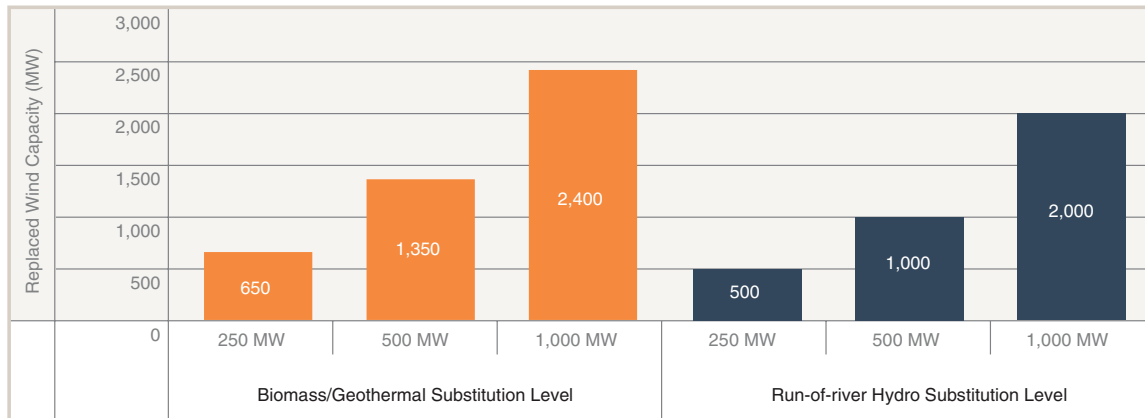
**FIGURE 12: Substitution cases**

	Run-of-river Hydro	Biomass	Geothermal
Substitution Case Inputs	250 MW	250 MW	250 MW
	500 MW	500 MW	500 MW
	1,000 MW	1,000 MW	1,000 MW

Since the dispatchable renewables simulated all have higher expected capacity factors than wind, different levels of installed wind capacity were removed from each scenario in order to hold renewable energy at 30 per cent by 2030.

Figure 13 summarizes the capacity of wind removed for the different substitution cases.

**FIGURE 13: Replaced wind capacity across substitution cases**



**6.1.3 Comparative costs and emissions results**

Comparing key metrics between the substitution cases and the 2018–MCTG case provides directional cost/benefit results.

Three cost categories were considered in the comparative analysis:

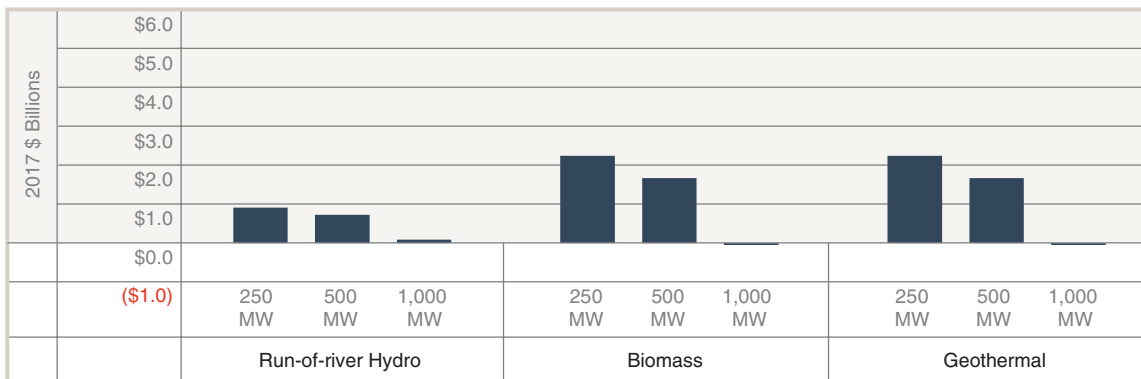
- Market costs
  - Those costs incurred in the energy, capacity, and ancillary service markets
  - These costs are recovered from ratepayers
- REP proxy costs
  - Costs based on using the levelized cost of energy (LCOE) for the dispatchable renewable as the proxy strike price in a contract-for-difference, REP-like payment structure
  - These costs are recovered from the carbon levy
- Emissions costs
  - Costs based on \$50/tonne applied to carbon emissions produced
  - These costs are provided separately for visibility but are included in market costs

Transmission interconnection costs were not directly considered in the comparative analysis, as these costs can be very specific to location and project capacity size. Transmission interconnection costs would be additive to the three cost categories above for specific projects. Refer to Appendix 5 for an approximation of the 25-year present value cost for different transmission interconnection cost levels.

**Market costs**

Figure 14 summarizes the present value over 25 years of the incremental market costs when comparing the nine substitution cases against the 2018–MCTG scenario. In all substitution cases, market costs are higher.

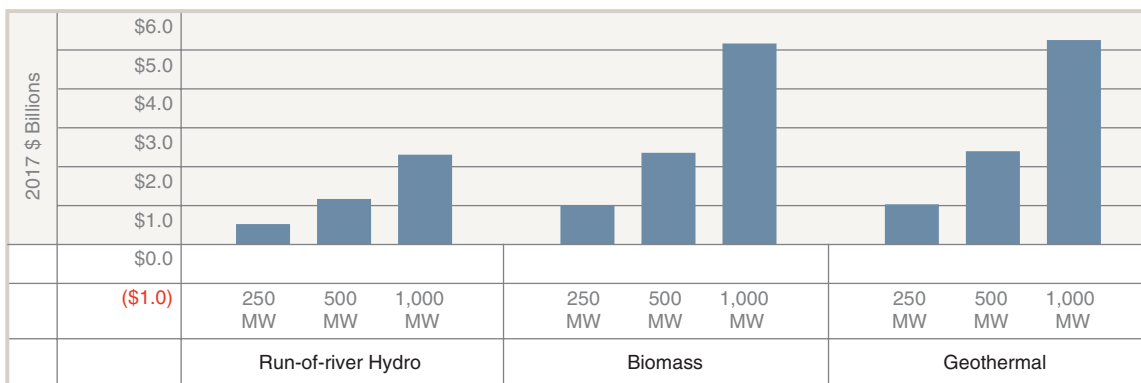
**FIGURE 14: Market cost – 25-year present value**



**REP proxy costs**

Figure 15 summarizes the present value over 25 years of the incremental REP proxy costs when comparing the nine substitution cases against the 2018–MCTG scenario. As more dispatchable renewables are substituted in, REP proxy costs increase to the \$5 billion range for the 1,000 MW cases.

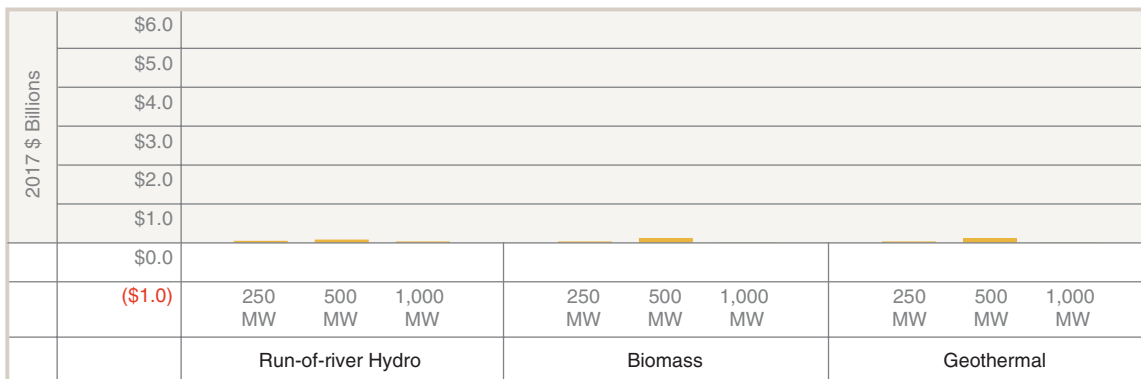
**FIGURE 15: REP proxy cost – 25-year present value**



**Emissions costs**

Figure 16 summarizes the present value over 25 years of the incremental emissions costs when comparing the nine substitution cases against the 2018–MCTG scenario. These costs are marginal, as zero emitting dispatchable renewables are replacing wind. Minor changes in gas generation supply mix in the substitution cases between simple-cycle and combined-cycle result in a slightly higher-emitting supply mix overall.

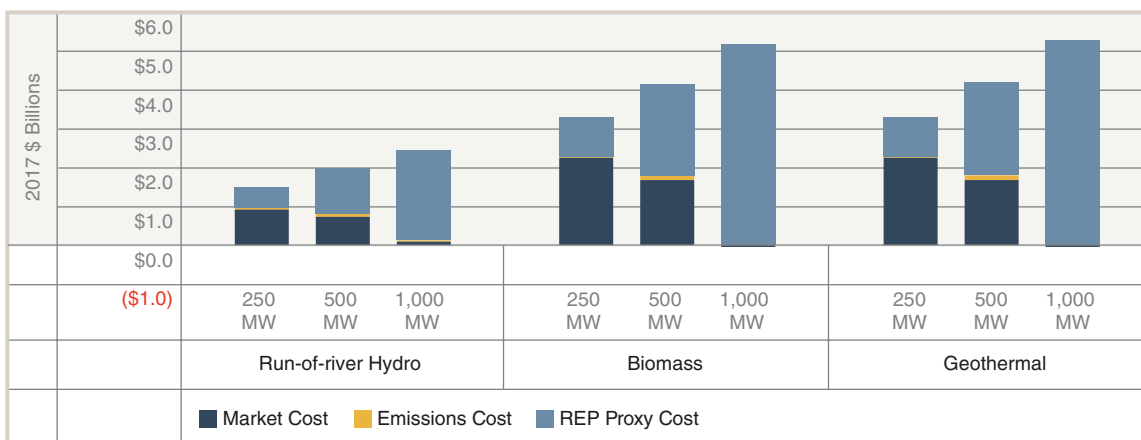
**FIGURE 16: Emissions costs – 25-year present value**



**Total cost**

Figure 17 combines the three cost categories to provide a total cost, in present value over 25 years. When comparing the nine substitution cases against the 2018–MCTG scenario, all dispatchable renewables substitution cases result in an increase in total cost ranging from \$1.5 billion to \$5 billion in 25-year present value cost. The 2018–MCTG scenario with wind as the primary renewable resource is the most cost-effective scenario.

**FIGURE 17: Total cost – 25-year present value**



**6.2 Conclusion: procuring dispatchable renewable energy is more costly**

The comparative analysis reveals that for all dispatchable renewable technologies, there is an overall increase in total costs. This is primarily a result of the following factors:

- Market costs increase
  - Capacity payments are reduced because less capacity is procured in the capacity market given that the dispatchable renewables capacity is procured through a REP-like program
  - Energy costs increase because of increased energy prices due to less wind in the market not pulling energy prices as far downward
  - These increases are greater than the capacity payment reductions, resulting in a net overall cost increase
  - Reaching 1,000 MW of dispatchable renewable capacity has a similar effect on pulling energy prices down as does wind, reducing the overall net cost to almost zero for market costs



- REP proxy costs increase
  - The higher levelized cost for various dispatchable renewables as compared to wind, drives a higher strike price and therefore a higher overall REP proxy cost as energy prices are more often below the higher strike price
- Emissions costs increase
  - The modest increase is due to a slight increase in less efficient gas generation being built for the dispatchable renewables scenarios versus the wind-based 2018–MCTG scenario, which marginally increases emissions

### 6.2.1 LCOE impacts on REP proxy costs

The LCOE can range due to financing and capital cost assumptions. The range in LCOE results in a corresponding REP proxy cost range, given the strike price will range accordingly. Figure 18 provides a table with various ranges for financing and capital cost assumptions and the corresponding REP proxy cost, by dispatchable renewable technology. For the broad LCOE ranges provided, almost all result in an increase in REP proxy costs when compared to the 2018–MCTG scenario.

**FIGURE 18: REP proxy cost ranges by LCOE**

	Capital Cost (2017 \$/kW)	LCOE		REP Proxy Cost by Substitution Level					
				250 MW		500 MW		1,000 MW	
		2017 \$/MWh		PV 2017 \$ B		PV 2017 \$ B		PV 2017 \$ B	
		Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)
Biomass	4,750	115	132	0.6	1.0	1.6	2.3	3.7	5.0
	5,000	117	135	0.7	1.0	1.7	2.4	3.8	5.2
	5,600	122	142	0.8	1.2	1.8	2.6	4.2	5.7
Geothermal	7,677	80	109	(0.0)	0.5	0.2	1.4	1.1	3.3
	9,801	98	136	0.3	1.0	1.0	2.4	2.5	5.3
	13,842	134	188	1.0	2.0	2.3	4.4	5.1	9.0
Run-of-river Hydro	4,000	50	67	(0.3)	(0.1)	(0.5)	0.0	(0.9)	0.1
	6,500	74	103	0.1	0.5	0.2	1.2	0.6	2.3
	8,000	89	124	0.3	0.9	0.7	1.9	1.5	3.6
	9,750	107	149	0.6	1.3	1.3	2.7	2.6	5.1
	13,000	139	195	1.1	2.0	2.3	4.1	4.5	8.0

Positive present value estimates mean an increase to REP proxy costs compared to 2018–MCTG, whereas a negative present value (shown in red) estimate represents a decrease to REP proxy costs compared to 2018–MCTG (also see Appendix 5).

LCOE assumptions: 25-year financial life for all technologies; 78% capacity factor for run-of-river hydro; 92% capacity factor and transportation costs (\$44/MWh) for biomass; 92% capacity factor for geothermal.

## 6.3 Summary

The key results from the cost/benefit analysis performed are:

- All scenarios studied were based on achieving the renewable energy target
- Dispatchable renewables are less cost-effective than wind, with total present value cost over 25 years ranging from \$1.5 billion to \$5 billion for 250 MW to 1,000 MW, respectively
- Wind energy is currently forecast to be the most cost-effective renewable energy; cost curves for solar may change this in the future
- Proceeding with any additional REP-like contracts for dispatchable renewables will also have an impact on the volume of capacity procured “out-of-market” and not through the future capacity market

See Appendix 5 for details of Section 6, including the modelling approach, cost assumptions and results.

# 7. Energy storage analysis

*Energy storage has flexibility attributes that may be beneficial to address future variability challenges on the system.*

Energy storage is an emerging technology, with the exception of the mature storage technology of pumped hydro. Energy storage is becoming more prevalent in the electricity industry as renewables penetration targets continue to increase and technology cost curves continue to decline. Energy storage does not easily fit into an industry structure (legislation, regulations, markets, processes, IT systems) that has historically been generation-wires-load-based. This is because energy storage has many attributes and depending on its application can be:

- Distribution-like when placed on the distribution system to reduce peak demand, congestion and defer build
- Transmission-like when connected to the transmission system to reduce peak demand, congestion and defer build
- Generation-like when discharging onto the grid to supply stored energy
- Load-like when charging from the grid to store energy to discharge at a later time onto the grid
- Customer-like when on the customer's side of the meter, managing customer bill costs

Unlike dispatchable renewables generation, energy storage does not create “new” electricity. Energy storage technologies store previously generated electricity by converting it through a charging process, holding the stored energy for a period of time and then releasing the stored energy as electricity. Different energy storage technologies have different overall efficiencies when going through a charge-store-discharge cycle. Energy storage is therefore a net consumer of electricity as it moves through the cycle of charging-storing-discharging. Energy storage has flexibility attributes that may be beneficial to address future variability challenges on the system, as most energy storage technologies can charge and discharge rapidly.

Many jurisdictions are working through how to capture the potential benefits energy storage can bring, the market enablement and participation models for energy storage, as well as the integration and application challenges energy storage brings when connecting to a generation-wires-load-based industry structure.

## 7.1 Energy storage study: approach

The AESO engaged Energy + Environmental Economics Inc. (E3), a San Francisco-based consulting firm with expertise in clean energy policy implementation, to conduct the energy storage study (see Appendix 6).

In order to provide directional results on the cost/benefit of various types of energy storage in the market, scenario simulations were utilized. The 2018-MCTG scenario was used as the base scenario for the storage analysis.

Two storage technologies were studied in order to assess short-duration, low-energy through to long-duration, high-energy storage capabilities. The most common energy storage technologies were utilized, with lithium-ion batteries representing the short-duration, low-energy storage technology and pumped hydro storage representing the long-duration, high-energy storage technology.

The AESO recognizes that there are other energy storage technologies that could have been analyzed, but time limitations constrained the analysis to two technologies. Future analysis can be performed to refine the energy storage results for different technologies. Compressed air energy storage (CAES) is typically a long-duration, high-energy storage technology for which pumped hydro storage will be a reasonable proxy for revenue capture.

The storage analysis followed this approach to assess overall revenues/costs:

- Using 1 MW of incremental storage, determine revenues
- Compare revenues against costs to determine energy storage's cost-effectiveness
- Test various energy storage durations to see if longer-duration storage is more beneficial
- Test 75 MW and 500 MW energy storage capacity to see if larger energy storage capacity is more beneficial or has declining marginal benefit

The revenue streams included:

- Energy market
- Ancillary services market, which includes regulating, spinning and supplemental reserves
- Future capacity market

The cost categories included:

- Capital costs including financing
- Operating costs, fixed and variable
- Charge/discharge costs including wholesale energy and transmission tariff costs

The storage model produces optimistic revenues for the following reasons:

- Storage bids in as a price taker, and therefore is always in the market receiving revenues
- Uses perfect foresight, therefore can predict with certainty the future highest-value market hour each day to capture revenues
- Uses hourly modelling in the ancillary services market, which is currently a block-hour market
- Can switch between markets every hour to maximize revenues

## 7.2 Energy storage study: results

### 7.2.1 Cost/benefit of 1 MW of storage

Figures 19A and 19B summarize the energy storage results for a 1 MW storage facility, comparing the 25-year present value of benefits with costs.

Figure 19A provides the results without including the transmission tariff costs incurred when charging the storage facility. Two different durations for lithium-ion battery storage were assessed (two-hour, four-hour) and two different durations for pumped hydro storage (six-hour and 12-hour). For each, the left bar includes the total revenues captured in the three markets and the right bar includes the total costs for the storage facility, both operating and capital costs. All revenues and costs are on a 25-year present value-per-MW basis for comparative analysis. When comparing revenues versus costs, shortfalls in revenue are shown in red dashed boxes and excess revenues are shown in green dashed boxes.

The results indicate that a 1 MW storage facility has net benefits (shown as green dashed boxes) for durations up to six hours and may be cost-competitive if no transmission tariff costs are incurred. The majority of the revenues are captured from the ancillary services market, with little to no revenues captured through price arbitrage in the energy market. Energy prices need to have a sufficient price spread between low daily prices and high daily prices in order for the energy price arbitrage process to be cost-effective.

**FIGURE 19A: 1 MW storage – 25-year present value with no transmission tariff costs**

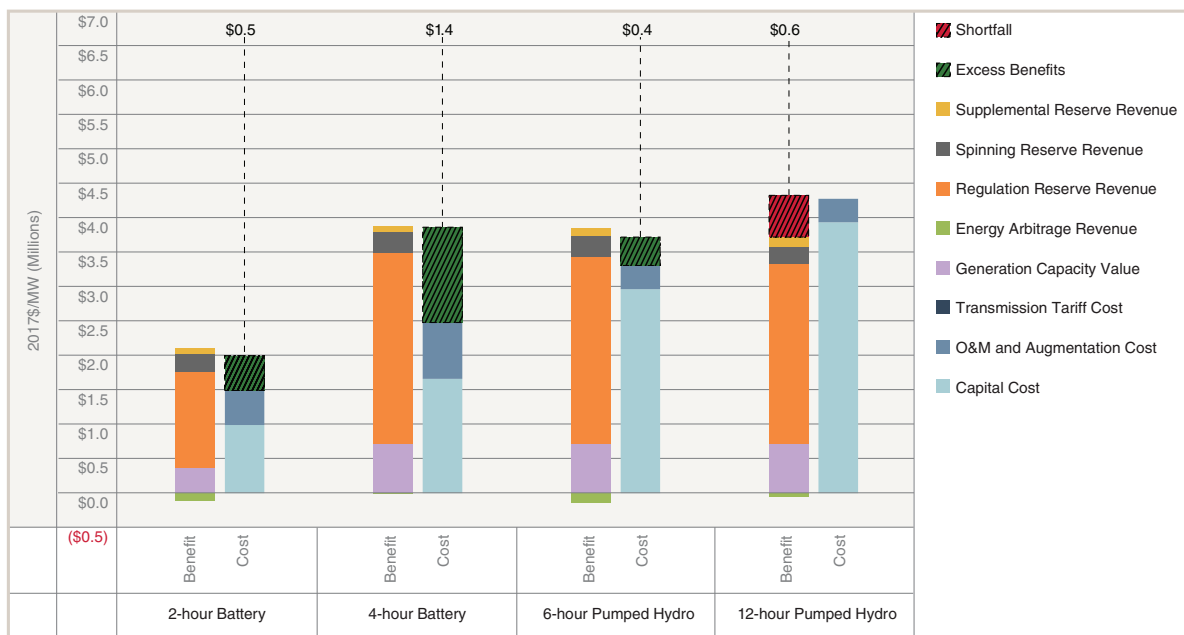
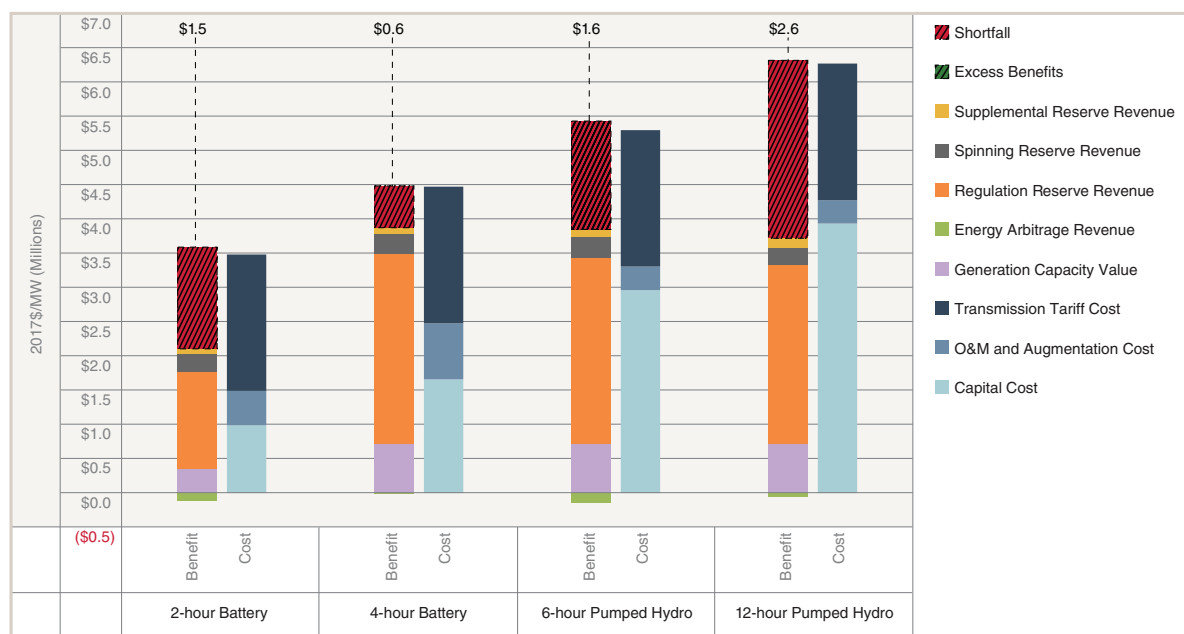


Figure 19B provides the same analysis but now with the transmission tariff costs included for charging. The transmission tariff costs are material, and cause all four cases to become negative net revenues (shown as red dashed boxes) and uncompetitive in the market.

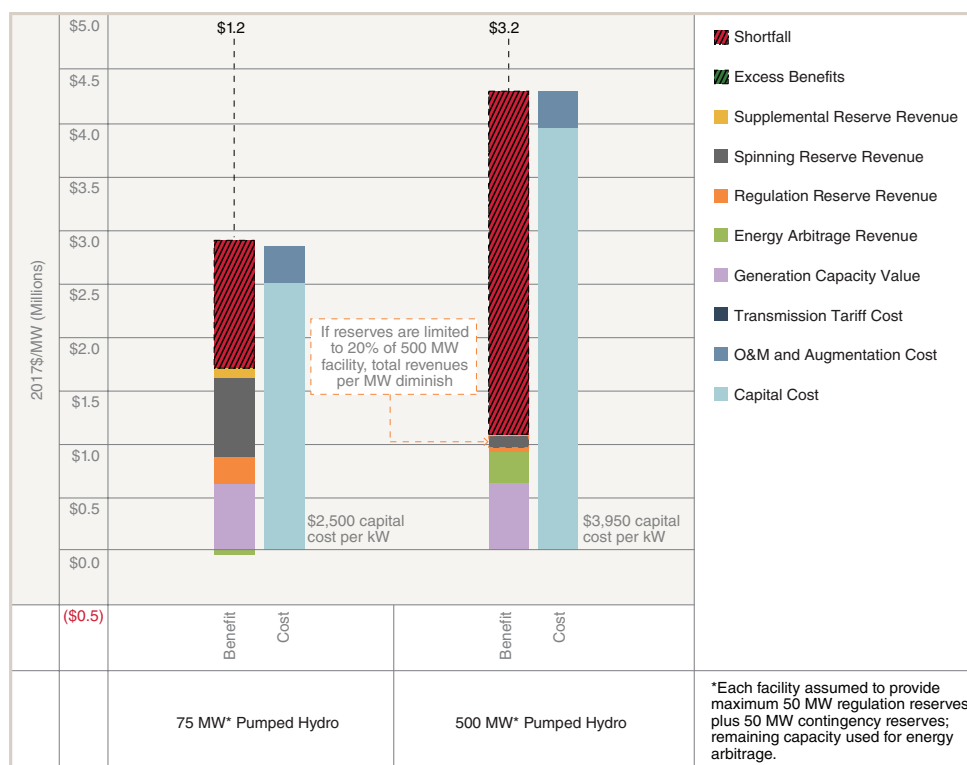
**FIGURE 19B: 1 MW storage – 25-year present value with transmission tariff costs**



### 7.2.2 Cost-effectiveness of larger storage volumes

In order to determine the cost-effectiveness of higher volumes of energy storage on the system, a 75 MW and 500 MW storage facility were modelled. Due to the small size of Alberta's ancillary services market, each facility was allowed to provide a maximum of 50 MW regulating reserves and a maximum 50 MW spinning and supplemental reserves. Even at these volumes, the prices in the ancillary services market will be impacted due to market saturation. There was no limitation on capturing energy price arbitrage revenues in the energy market. Figure 20 provides the results of this analysis. The results indicate both the 75 MW and the 500 MW storage facilities are not cost-effective with negative net revenues (shown as dashed red box). The increased costs associated with the larger storage facilities were not able to be offset by increased revenues in the market. This is primarily because the ancillary services market is where the highest-value revenues are for storage facilities, but it is a small market that cannot provide sufficient revenues for large storage volumes. The energy market also does not provide sufficient revenues to offset the additional costs, as energy price spreads are not sufficient to make energy price arbitraging profitable.

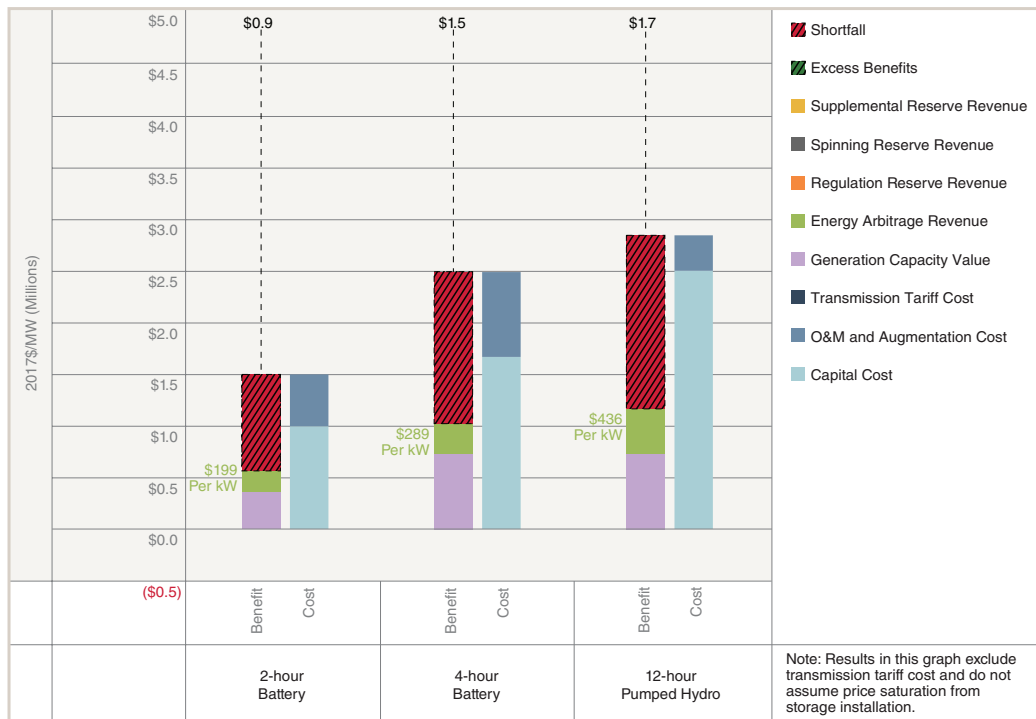
**FIGURE 20: Effect of larger storage volumes (includes price saturation on ancillary services)**



### 7.2.3 Cost-effectiveness of longer storage duration

In order to determine the cost-effectiveness of longer-duration storage, three different storage durations were modelled, allowing the storage facility to access energy arbitrage revenues only. Figure 21 provides the results of this analysis. A 100 per cent increase in the storage duration from two hours to four hours only results in a 45 per cent increase in energy arbitrage revenues. A further 300 per cent increase in storage duration from four hours to 12 hours only results in a 51 per cent increase in energy arbitrage revenues. Increasing storage durations is not cost-effective as the increase in revenues does not offset the increase cost for long-duration storage facilities.

**FIGURE 21: Effect of longer-duration storage (for energy arbitrage revenues only)**



### 7.3 Energy storage study: conclusion and next steps

The following summarizes the key observations from the storage results above, based on current storage costs:

- A small amount of short-duration storage may be cost-effective, primarily capturing revenues from the ancillary services market
- Since the ancillary services market is relatively small in size, the market will saturate quickly with additional storage
- Energy prices are unlikely to have sufficient price spreads in the future to provide sufficient incremental revenues through energy price arbitrage to support the incremental capital cost of longer-duration storage (greater than four hours)
- The current transmission tariff treatment of storage as a load when charging, may be prohibitively costly for otherwise cost-effective storage participation in the ancillary services market

Numerous jurisdictions have developed energy storage roadmaps to proactively set a path within the industry for the evolving technology. The future for energy storage competitiveness is uncertain. However, as the industry world-wide continues to invest in research and development to further reduce costs and improve capabilities, there is significant momentum driving the technology forward. As a next step, the AESO will develop an Energy Storage Roadmap for Alberta's electricity system and seek input from industry stakeholders.

The objectives of the Energy Storage Roadmap are:

- Identify and remove barriers associated with energy storage's participation in the electricity markets, such as changes to tariff structures specific to storage
- Enhance the AESO's internal capabilities, collaboration across the industry on research and development, and industry awareness of energy storage technologies as the technologies advance
- Further advance energy storage definitions, and if necessary, recommend future legislative, regulation and rule changes



# 8. Regulatory and legal review

*The AESO performed a regulatory and legal review pertaining to dispatchable renewables and energy storage to identify potential gaps and inconsistencies in Alberta's existing legal and regulatory framework that may need to be addressed.*

The AESO performed a regulatory and legal review pertaining to dispatchable renewables and energy storage to identify potential gaps and inconsistencies in Alberta's existing legal and regulatory framework that may need to be addressed. The review included an examination of applicable rules and legislation, Alberta Utilities Commission (AUC or Commission) guidance and general technical considerations.

The full review can be found in Appendix 7.

## 8.1 Dispatchable renewables definition

The phrase “dispatchable renewables” is not legislatively defined. However, the meaning of the phrase may be garnered from existing definitions of “dispatch” and “renewable energy resource.”

“Dispatchable” has a commonly understood meaning in Alberta, referring to the ability of an asset to be dispatched. The term “dispatch” is legislatively defined in the *Electric Utilities Act* (EUA) as follows:

“dispatch” means a direction from the Independent System Operator to a market participant to cause, permit, or alter the exchange of electric energy or ancillary services.

Accordingly, an asset is “dispatchable” if it is capable of responding to a dispatch in accordance with the ISO rules.

An asset is considered “renewable” if it produces electricity from a “renewable energy resource” as defined in the *Renewable Electricity Act* (REA). The REA defines “renewable energy resource” as:

[...] an energy resource that occurs naturally and that can be replenished or renewed within a human lifespan, including, but not limited to,

- (i) moving water,
- (ii) wind,
- (iii) heat from the earth,
- (iv) sunlight, and
- (v) sustainable biomass.

While legislative changes may not necessarily be required to incorporate the concept of dispatchable renewables within Alberta's existing regime, there may be a benefit to creating either a new definition or new term, depending on how these resources will participate in the future.

## 8.2 Energy storage definition

An “energy storage facility” is a facility that converts electric energy by charging, stores the converted energy for a period of time, and releases the stored energy when it discharges. This cycle incurs energy losses, meaning that an energy storage facility is a net consumer of energy. By extension, an energy storage facility is not a net producer of energy and would not be considered a dispatchable renewable asset. However, an energy storage facility may bring benefits to an existing renewable asset by storing energy from that renewable asset and discharging the stored energy at a later time.

The Federal Energy Regulatory Commission (FERC), which regulates the transmission and wholesale sale of electricity in the U.S., after an extensive review and industry engagement process, recently defined an electric storage resource as:

“a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.”

The Ontario Independent Electricity System Operator, which is the first ISO and jurisdiction in Canada to competitively procure energy storage, has defined three different types of energy storage depending on the particular storage application, which can be found in Appendix 7.

As noted in FERC Order No. 841, “electric storage resources” have unique physical and operational characteristics. Energy storage facilities do not easily fit within the existing framework because, depending on their use, energy storage facilities may provide attributes of load, generation, transmission facilities, distribution facilities, or more. However, in the absence of a framework tailored to the unique attributes of energy storage facilities, it is usually necessary to attempt to classify energy storage facilities by referencing conventional categories such as “load” and “generation,” or “distribution” and “transmission.”

The AESO supports a definition that focuses on three defining characteristics of an energy storage facility, namely its ability to charge, store and discharge energy. This approach does not impose restrictions on where, when, and how these functions occur, or the application of the energy storage facility.

Alberta, like other jurisdictions, is dealing with the challenges associated with a consistent definition of energy storage, given that energy storage is a unique technology in the electricity industry. These challenges include defining energy storage and adapting existing regulations, legislation and market rules to incorporate energy storage. As part of the AESO’s Energy Storage Roadmap, described in Section 7.3, the AESO intends to engage stakeholders to help inform a definition for energy storage, and identify potential future regulation, legislation and market rule changes that would assist in advancing energy storage integration.

### 8.3 Characteristics of dispatchable resources

Incorporating the general definitions of dispatchable, renewable and storage, Figure 22 provides a categorization of these characteristics for different dispatchable resources.

**FIGURE 22: Characteristics by resource**

Resource	Dispatchable		Renewable	Storage
	Up	Down		
Simple-cycle	✓	✓		
Combined-cycle	✓	✓		
Wind		✓	✓	
Solar		✓	✓	
Run-of-river hydro	✓	✓	✓	
Biomass	✓	✓	✓	
Geothermal	✓	✓	✓	
Battery	✓	✓		✓
Pumped hydro	✓	✓		✓
Compressed air	✓	✓		✓

# 9. Conclusions and next steps

*The AESO has concluded dispatchable renewables and energy storage are not required for system reliability leading up to 2030.*

The AESO's analysis to date forecasts no material reliability or flexibility challenges to integrating 30 per cent renewable energy by 2030. The current market-based approach of procuring the needed flexibility in the energy market and in the ancillary services market is forecast to reliably deliver on the future variability needs on the system. As such, there is no emerging need for a specific procurement to meet additional flexibility requirements.

In assessing whether different dispatchable renewables resources can more cost-effectively deliver on the renewable energy target, the AESO's analysis concludes that wind energy remains the most cost-effective renewable energy to procure. Since there exists no emerging need for a specific flexibility-related procurement, all different types of dispatchable renewables should continue to compete in future REP rounds.

In assessing whether energy storage can cost-effectively participate in Alberta's electricity markets, the AESO's analysis concludes that low-energy, short-duration storage applications, such as lithium-ion batteries, may be able to cost-effectively compete, primarily in the ancillary services market, if certain market rules and transmission tariff treatments are addressed. High-energy, long-duration storage applications, such as pumped hydro storage or compressed air energy storage, may not be able to cost-effectively compete in the electricity markets. This is primarily because the incremental cost of high-energy, long-duration storage applications may not be recovered through energy price arbitrage revenues in the energy market, or through the small-sized ancillary services market.

## 9.1 AESO's next steps

As a result of the analysis performed for dispatchable renewables and energy storage, the AESO will proceed with the following next steps as a normal course of business:

- The AESO will develop an Integrated Flexibility Roadmap, with input from industry stakeholders, to provide a sustainable process to assess future flexibility needs
- The AESO will develop an Energy Storage Roadmap, with input from industry stakeholders, to ensure that as technologies develop, barriers to integration are not created, and that tariff structures appropriately recognize the unique aspects of storage systems
- Upon direction from the Government of Alberta, the AESO will engage stakeholders in the results of this analysis, seek feedback on the analysis and incorporate feedback into the AESO's development of the Integrated Flexibility Roadmap and Energy Storage Roadmap

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## 9.2 Recommendation to the Government of Alberta

The Government of Alberta sought to gain a better understanding of whether there was a system reliability need for additional dispatchable renewables and energy storage.

The government tasked the AESO to conduct a review of the electricity system requirements leading up to 2030, and to provide a recommendation based on its findings. The recommendation was to specify if there was a need for additional products or services and, if the analysis supported a need, what market mechanisms or competitions may be required. In addition, the AESO was asked to recommend a definition for dispatchable renewables informed by the review.

Based on the analysis within this report, the AESO has concluded dispatchable renewables and energy storage are not required for system reliability leading up to 2030. Therefore, the AESO recommends that no additional products or services for these resources are needed at this time.

This recommendation is further supported by cost/benefit analysis that forecasts any dispatchable renewable resource as less cost-effective than those resources currently procured in the REP. Consideration should also be given to the impact an additional procurement may have on the effective function of the future capacity market.

The AESO recommends defining dispatchable renewables through existing legislation by combining the definition of “renewables” in the *Renewable Electricity Act* with the definition for “dispatch” in the *Electric Utilities Act*.

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Appendix 1:  
Government of Alberta request letter

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Energy  
Office of the Deputy Minister  
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9945 - 108 Street  
Edmonton, Alberta T5K 2G6  
Canada  
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Fax: 780-427-7737  
Email: [Coleen.Volk@gov.ab.ca](mailto:Coleen.Volk@gov.ab.ca)  
[www.alberta.ca](http://www.alberta.ca)

November 29, 2017

AR29445

David Erickson  
Alberta Electric System Operator (AESO)  
[david.erickson@aeso.ca](mailto:david.erickson@aeso.ca)

Dear Mr. Erickson:

The Government of Alberta would like to better understand the potential role for dispatchable renewables, as Alberta transitions to the new electricity market structure and progresses towards the 30 per cent renewable electricity generation by 2030 target.

The government appreciates the potential value that on-demand renewables can provide to Alberta's electricity system reliability, especially as significant intermittent generation is brought onto the grid through initiatives such as the Renewable Electricity Program (REP). We also recognize the importance of ensuring any approach specific to dispatchable renewables is consistent with Alberta's competitive generation market.

To that end, additional analysis and stakeholder engagement is required to determine the precise need, and subsequent best means, to secure these system benefits through a competitive process compatible with Alberta's electricity market. The Government of Alberta requests the AESO to conduct a review of the electricity system requirements as described above, engaging technical and other stakeholders as necessary, and that this be completed by May 2018.

The AESO is further requested to consider the findings of this review and prepare a recommendation to the Government of Alberta detailing:

- I. whether any additional products or services are required;
- II. if so, whether they may be procured using existing market mechanisms or whether discrete competitions will be required; and
- III. if discrete competitions are required, a proposal as to the structure and timeline of such competitions.

If, at the end of the process set out above, an identified need for discrete competitions is established, recommendations on competition design—be it through REP or otherwise—need to be completed by August 2018. Subsequent competition would need to be launched no later than November 2018, pending approval from the Minister.

.../2

We also request that recommendations be developed consistent with the following desired outcomes, should the review point towards the need for additional products and services:

- Contribute towards meeting the Government of Alberta's target to ensure that at least 30 per cent of electricity is produced by renewable sources by 2030, as per Section 2 of the *Renewable Electricity Act*.
- Maintain or improve the future reliability of Alberta's electricity grid.
- Ensure minimal market impacts outside of the desired outcomes.
- Meet Alberta's electricity system needs in a cost-effective manner (inclusive of indirect costs such as transmission requirements).

The review is to include all forms of renewable generation typically associated with the ability to be dispatched when required—hydroelectricity, biomass and geothermal—as well as the role electricity storage can play to enhance the availability of these sources and to firm wind and solar. Furthermore, as part of the process of determining system need, AESO should also put forward a recommended definition for dispatchable renewables informed by this engagement.

Lastly, we request that all engagement be framed as information gathering to inform future decisions, with no commitment to specific outcomes until such a time that the Minister directs you otherwise.

Sincerely,



Coleen Volk  
Deputy Minister

cc: Mike Law, Alberta Electric System Operator

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# Appendix 2:

## Stakeholder questionnaire

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# Appendix 2: Stakeholder questionnaire



## Introduction

The AESO invites interested stakeholders to provide their views on dispatchable renewable resources and electricity storage in Alberta. Please complete this questionnaire and return it to [dispatchablerenewables@aesO.ca](mailto:dispatchablerenewables@aesO.ca) by Feb. 14, 2018.

The AESO appreciates that feedback may include sensitive business information and expressly accepts this information in confidence to encourage fulsome and accurate participation. Profile information related to each response is being collected for the purposes of facilitating clarification and follow-up activities, as well as allowing the AESO to aggregate the results in a meaningful way.

The AESO is a public body subject to the provisions of the Freedom of Information and Protection of Privacy Act ("FOIP Act"). Access to information rights granted under the FOIP Act are subject to mandatory exceptions to disclosure that prohibit access to certain third party information supplied explicitly or implicitly in confidence, when disclosure could reasonably be expected to, among other things, significantly harm the business interests of a third party or when disclosure would unreasonably invade an individual's privacy (FOIP Act, Sections 16 and 17 respectively).

If third party information is requested under the FOIP Act, the AESO is required to notify each affected party and request representations regarding disclosure.

Questions related to participation in this process can be directed to [dispatchablerenewables@aesO.ca](mailto:dispatchablerenewables@aesO.ca).

## Questionnaire

Tell us about yourself. This information will assist the AESO in its assessment but will not be made public.

1. Please provide your name, email address, phone number, and the organization you represent.

2. What is your interest in responding to the AESO's questionnaire (i.e. are you a developer, investor, association, interested party, etc.)

3. If you are a developer or asset owner, please describe the type of dispatchable renewable or electricity storage project(s) you are building, have built, and/or operate, including size and location.

4. If you are a developer or asset owner, please indicate your interest in future development of dispatchable renewables or electricity storage projects in Alberta and why.

Please tell us your views on the following:

5. The role for dispatchable renewable resources and electricity storage in Alberta.

6. The need for dispatchable resources, particularly renewable based, and/or electricity storage within Alberta, now and in the future as Alberta transitions to 30% renewables by 2030.

7. Other dispatchable resources (technologies) to consider, now and in the future.

8. Other jurisdictions to learn from.

9. The barriers that exist today to developing more dispatchable renewables and/or storage, including, but not limited to: financing, construction, technology, permitting and approvals – including environmental, legislative or regulatory framework, etc.

10. The pros and cons of dispatchable renewables and/or electricity storage in Alberta.

11. Please provide any other general comments and/or feedback you feel would be helpful to the AESO with respect to dispatchable renewables and storage.

Thank you for your participation in this survey. In addition to your survey responses, if you have documentation you feel would be beneficial to the AESO's assessment of dispatchable renewable resources and electricity storage, please email it to [dispatchablerenewables@aeso.ca](mailto:dispatchablerenewables@aeso.ca).

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# Appendix 3:

## Stakeholder feedback summary

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# Appendix 3: Stakeholder feedback summary



## Introduction

The AESO thanks all those who submitted a response to our stakeholder questionnaire on dispatchable renewables and storage (DR&S) in Alberta. Each response was reviewed thoroughly and the information received will help inform the AESO's report to the Government of Alberta on how dispatchable renewables and storage could benefit the electricity system.

To gather more in-depth feedback, the AESO also conducted one-to-one discussions with 30+ organizations representing a wide range of interested stakeholders. This document includes a summary of what we heard. The AESO takes no position on any of the comments provided by stakeholders. Participants' identifiable information is kept strictly confidential to protect their privacy.

As requested by the government in its direction letter, the AESO's work will focus on the following:

- What, if anything, is needed on the power system to integrate 30 per cent renewables by 2030, particularly to address any challenges intermittent renewables may bring to the grid
- Determining whether additional specific products or services may be required
- If so, how they should be procured, either through use of existing market mechanisms or via discrete competitions
- If discrete competitions are required, a proposal as to the structure and timeline of such competitions

## Summary of Stakeholder Feedback from Dispatchable Renewables and Energy Storage (DR&S) Questionnaire

A total of 88 survey submissions were received from stakeholders. Due to the dual nature of many submissions, respondents could not be identified within one specific category (e.g., an existing generator also exploring new development opportunities). The list below captures the multiple interests of the various stakeholders that made submissions.

### Respondents/Participants

- 59 developers/investors
- 20 power industry (generators, transmission/distribution owners, others)
- 13 interested parties
- 8 unidentified
- 8 supply/support chain
- 4 associations/organizations

The AESO has summarized the feedback received from stakeholders into the following sections:

- 1) Need for DR&S in Alberta
- 2) Role of DR&S
- 3) Technology–Specific Feedback
- 4) Barriers to DR&S
- 5) Pros and Cons of DR&S Development
- 6) Other Jurisdictions: Learning Opportunities
- 7) Additional Stakeholder Comments

## 1. Need for DR&S in Alberta

Stakeholders indicated a broad range of experience, identifying projects developed around the globe and across a full spectrum of DR&S technologies. Project developments included numerous storage projects, either co-located with wind or solar generation or as standalone assets. Many had already achieved success in developing or owning battery storage projects, at both small-scale and utility-scale. Hydroelectric and biomass generation were also among the asset classes developed by respondents.

A number of key themes around the need for DR&S emerged from the survey responses:

### *Supporting Grid Evolution*

- The evolving grid must accommodate a diversity of DR&S technologies, not just wind and solar
- DR&S will help the provincial power sector to evolve as an efficient, sustainable and environmentally responsible entity; an opportunity for Alberta to show global leadership
- More diverse generation mix will maximize progress toward Alberta’s sustainable energy goals
- Supports efforts to help achieve provincial and national emissions reduction targets; can also prevent gas from becoming Alberta’s ‘new coal’
- DR&S will become a critical component of ensuring grid reliability
- DR&S can allow deferral of transmission and distribution investments
- Provides targeted deployment to support grid transformation
- Provides consumer benefits: reduced energy costs, price stability; improved reliability
- DR&S will maximize value of investments in renewable assets, especially when paired with storage

## 2. Role of DR&S

- Improved grid operational flexibility, resilience, stability and level of control (time-shifting capability)
- Transmission optimization; improved efficiency, congestion management, maintaining power quality
- Multi-purpose assets that can respond to fast variations, regulate power quality
- DR&S can deliver a broad range of services:
  - Voltage and frequency management
  - Dynamic reactive power support
  - Reactive power support at low voltages
  - Reactive power support on individual phases
  - Fast-ramping capability
  - Fast response to regulating reserve
  - Spinning reserve and ancillary services markets
  - Black start and transmission-must-run services
- Co-located storage + solar will support variable generator capacity firming; variable generator ramping service; variable generator smoothing; curtailment mitigation; peaking capacity; VAR support; peak shaving
- Could encourage advancement of biomass technology; could create new revenue streams for forestry and agricultural sectors, and alternatives for landfill management

- Storage will keep consumer costs low by absorbing excess renewable generation
- Storage = improved consistency of overall generation profile; will prevent curtailments of wind/solar
- Could encourage advancement of pumped hydro development
- DR may be required to backstop thermal generation if gas prices spike or gas supplies are curtailed

### 3. Technology–Specific Feedback

The following summarizes common responses/themes; grouped by technology:

#### ***Storage proponents (battery, compressed air energy storage, pumped hydro)***

- AESO may need to direct storage to locate near DR to maximize benefits
- Storage could reduce/defer need for hydro development
- Storage can provide fast response to regulating reserve, spinning reserve and ancillary services markets; also black start and transmission-must-run services
- Storage will encourage increased development of microgeneration
- Storage should be considered in Renewable Electricity Program (REP) procurements
- Storage is an alternative to traditional wires-based solutions on distribution system
- Storage will prevent need to ‘waste’ energy by exporting power at distress prices
- Storage optimizes non-flexible thermal generation (e.g., cogeneration) by preventing sub-optimal operation that increases emissions per unit of generation
- Need market-based incentives to enable storage to deliver variety of grid services
- Pumped hydro provides higher cost/benefit value than battery; best opportunity for local downstream economic benefits (construction services, supply chain, etc.)
- Batteries should be considered to ‘flatten’ intermittency of renewables
- Battery storage is a modular resource; smaller amounts of capacity can be added as needed to meet evolving grid needs; can be co-located or sited at areas of highest need
- Pumped hydro is an excellent solution to ensuring fast ramping and dispatchability are covered during transition to renewables
- Strategic storage placement could eliminate need for capacitor banks, SVC, STATCOM elsewhere
- Storage increases hosting capacity of distributed energy resources (DER) on a distribution system
- Rules must allow storage to compete on a level field with new gas generation
- Storage is only asset class capable of mitigating oversupply and reducing curtailment of intermittent renewables; AESO should prevent oversupply situations by starting a procurement process now
- Pumped hydro should advance now as long lead times are involved
- Flexibility of storage can replace need for peaking gas assets
- Co-located storage + solar will support variable generator capacity firming; variable generator ramping service; variable generator smoothing; curtailment mitigation; peaking capacity; VAR support; peak shaving
- Co-location of solar + storage is more efficient and cost-effective than locating units separately
- Storage + DR will allow higher levels of integration with better grid performance
- Aggregation of multiple DER with co-located storage offers opportunity to harness consumer-level generation

#### ***Generation proponents (solar, wind, hydro, biomass)***

- Biomass and biogas development as baseload; reduces need for gas-fired assets
- Growth of biomass will create new revenue streams for forestry and agriculture sectors, and alternatives for landfill management
- Run-of-river hydro should incorporate some degree of storage capacity
- Solar DER is most manageable form of DR for distribution facility owners
- Without dispatchability, new renewable assets will just be offsetting/curtailing existing ones or facilitating exports

- B.C.-based hydro should be considered as part of a DR solution
- Hourly/monthly solar production curves align well with Alberta demand load for most of the year; reduces size of storage component required
- DR is an absolute necessity to avoid intermittency issues
- Small-scale solar DER an option for large urban areas
- Footprint of utility-scale solar makes poor use of prime agricultural lands
- Time-of-use metering would incentivize solar development
- Solar offers some desirable dispatch components (e.g., frequency regulation, daytime peak matching)
- No systematic effort being made to assess Alberta's hydroelectric potential
- Biomass is not widely recognized in Alberta despite abundant feedstock from forestry operations; too much focus on wind/solar
- Anticipated large renewables footprint will require fast-ramping DR to meet intermittency challenge
- Public enthusiasm for renewables may decline if extensive integration causes operational issues impacting reliability or supply adequacy
- In Europe, wind and solar dispatches on two-day look-ahead with 90 per cent probability
- As DER penetration increases, DR can be used to manage voltage, frequency, and reactive and real power flows on the distribution system
- Widespread integration of DR can cause significant transmission congestion, resulting in negative pricing and curtailments – presents major risk to developers and investors
- Price signals should adequately manage the addition of new DR; currently no need for DR as market signals are not incenting new gas-fired facilities

### ***Emerging and commercial technologies***

There were several comments regarding emerging or early commercially viable technologies to consider:

- Centralized fusion technology – for large urban areas
- Geothermal
- Kinetic energy storage
- Flow batteries
- Flywheel
- Hydrogen/fuel cells
- Pumped heat electrical storage (PHES)
- Residential wind turbines
- Cogeneration facilities sized for dispatchable export volume
- Lithium ion batteries
- Bioenergy – anaerobic digestion, landfill gas
- Electric vehicle charging stations
- Gravity batteries
- Waste heat from industrial processes
- Combined heat and power (CHP)
- Small modular nuclear reactors
- Installation of storage within load-serving entities (LSE) such as municipal distribution networks, and in support of transmission-connected commercial/industrial customers, allows LSE to become dispatchable loads

## 4. Barriers to DR&S

The following are common responses and themes, grouped by category, for barriers to DR&S:

### *Regulatory and governance*

- Need for improved regulatory certainty on longevity of DTS charges and rules
- Regulatory risk: protracted, confusing, unclear regulatory process
- Regulatory process has too many unknowns regarding storage
- Existing AESO Rules written for thermal generation; need upgrading
- AESO Rules for storage lack clarity
- Lack of provincial legislation addressing storage
- Needs to be a fast-track regulatory process for quiet, non-emitting sources such as battery storage, especially if procurement is via a competitive process
- Multiple interconnecting processes: AUC, AESO, Alberta Energy Regulator (AER), Alberta Environment and Parks (AEP), municipal governments

### *Markets*

- Limited revenue opportunities
- Investors lack confidence and clarity on revenue streams
- Financing challenges (e.g., need for long-term offtake structures to provide revenue certainty)
- Lack of long-term, investment-grade contracting opportunities
- Some investors holding off until rapid pace of tech advancements slows (risk of obsolete assets)
- Overall uncertainty about success of new capacity market and/or ancillary services market
- Ancillary services market is very small and dominated by a single player
- Market share controlled by incumbent generating sources
- Incumbent generators are most influential advisors to AESO; work to stifle competition and entrench old assets/models
- Capacity market design may impede deployment of non-subsidized renewables
- Uncertainty around coal retirement schedule and transition process
- Historic treatment of small developers in Alberta power sector
- Lack of comprehensive development plan for hydro
- Lack of funding for technology and prototype development, demo projects
- Lack of familiarity with suppliers
- Long-lead projects (i.e., hydro) require different procurement model and longer offtake agreements

### *Technology*

- No recognition/monetization of value of specific attributes of renewables
- Typical entry-level barriers encountered by all new technologies; some successful demo projects always needed to accelerate the integration
- Shortage of qualified labour pool for unfamiliar technologies
- Lack of understanding of biomass' specific benefits
- Technical challenges specific to technology type (e.g., scalability of battery storage)
- Current design of storage tariffs, required to pay wires fees when both charging/discharging
- Ability to capture full value of storage; can perform multiple functions beyond time shifting; need market mechanisms to unlock this value
- Lack of Alberta lender experience/comfort with storage technologies
- AESO views storage as a system burden rather than an asset; not part of planning framework



## 5. Pros and Cons of DR&S Development

Common responses and themes are summarized and grouped by category:

### *'Pro' comments*

- Adds flexibility, resilience and efficiency; improves power quality, stability/reliability, grid optimization
- Rapid deployment; can right-size solutions as needed
- Greater variety of assets responding to periods of stress
- Reduces need for asset redundancy, building capacity to address intermittent renewables
- Creates downward pressure on prices; benefits consumers
- Abundant wind/solar resources here
- Would ensure integrity of energy prices within each hour and optimize overall cost of supply in go-forward market
- Supports '30 by 30' and emissions reduction policy goals
- Can be achieved using Alberta businesses and expertise
- Reduced need for transmission upgrades
- Will decrease our reliance on fossil fuels and reduce emissions; renewables should always receive priority regardless of price or cost
- DR&S development gives new technologies an opportunity to gain a foothold
- Greater variety of technologies in supply mix increases diversification of job opportunities
- Solar offers predictable daytime production profiles when paired with satellite/radar weather imaging/mapping
- Pumped hydro is an established technology; carries no new-tech risk; fast-ramping with long discharge time (8+ hours)
- Solar PV offers fastest capacitor-based dispatch capability; daytime peak matching with Alberta loads corresponds well to predictable solar outputs
- Solar is a perfect generation spectrum fit with oilsands cogeneration
- A more dispatchable fleet of renewables (via storage) will slow the build-out of gas-fired generation and reduce the long-term risk of stranded gas-fired assets
- Storage is highly flexible, provides value across supply chain regardless of supply mix
- Storage provides non-wires alternative to poles-and-wire approach to mitigating system deficiencies
- Thoughtful locating of battery storage within high-density urban areas can provide quick short-term response when needed
- Higher possibility of integration into Distributed Energy Resource Management System (DERMS) to manage and optimize DER
- Virtually no 'cons' to DR&S except that current prices are lower than generation cost
- Any policy/procurement design should allow for rapid cost and technology advancements

### *'Con' comments*

- Developers will only incorporate storage if its value to the grid can be reliably monetized; fair market structures will attract investment
- Initial financial stimulus may be required; potential for political risk
- Regulation and policy amendments required
- Rapidly declining costs creates uncertainty for longer-term commitments
- Cost of some technologies (e.g., pumped storage) require huge, long-term investments; could result in stranded assets that don't evolve with the system
- Concerns about dampening price signals and distortion of markets
- Some risk involved in integrating new/emerging technologies
- Integration presents new planning and operational challenges for AESO
- Government needs to continue programs to ensure effective and timely development of technologies in order to achieve policy goals

- Increased integration of renewables increases risk of curtailments; storage is the solution
- DR&S should be implemented when technologies reach economic and technical parity
- Building a combination DR&S projects increases cost, incurs conversion/storage losses
- Requires sophisticated connection analysis to encourage flexible projects to connect
- Wind/solar needs storage component to achieve dispatchability; biomass needs no additional infrastructure (i.e., storage) to achieve baseload
- May have impact on prices, primarily affecting large-load industrial customers
- Biomass is typically baseload and would require coordinated demand response to become dispatchable; a capital-intensive asset that takes longer to build
- Co-location of DR and storage does not guarantee optimization, so non-co-located assets should be considered
- A dispatchability requirement will make building renewable assets more costly, but make them conform to same technical requirements and dispatch rules as other generators
- DR&S will complement supply, but complicate market rules for selling electricity
- Reliability and longevity of storage batteries may still be an issue
- Integration of new technologies could cause disruption of market framework and grid operation, but also synergies and benefits

## 6. Other Jurisdictions: Learning Opportunities

Participants suggested a wide range of jurisdictions to consider learning from. Those most frequently identified are listed below.

- New England Independent System Operator (NE-ISO)
- PJM Interconnected
- New York Independent System Operator (NY-ISO)
- Electric Reliability Council of Texas (ERCOT)
- United States (general)
- California
- Hawaii
- Arizona
- New York
- Massachusetts
- European Union (general)
- Germany
- United Kingdom
- Ireland
- Australia
- Ontario
- British Columbia

## 7. Additional Stakeholder Comments

Respondents provided additional insightful comments, observations and suggestions. These are summarized and grouped by category:

### *Policy development and system planning*

- Alberta has an opportunity to be a Canadian leader in renewables penetration while providing low-cost power to consumers
- Alberta's '30 by 30' target is lower than many American states; still plenty of room for renewables in our generation mix
- AESO should account for DR&S outside of the 5,000 MW REP procurement target

- Cost/benefit of DR&S should be evaluated against emerging technologies before moving forward
- AESO must be very clear on what specific DR attributes it is looking for
- Any policy design should create a runway for the most competitive solutions, not pick winners
- REP could be increased to allow greater DR penetration, mitigate ‘dash to gas’
- Need to apply fairness across all generation types in creating a sustainable grid; none should receive subsidies or other preferential treatment
- Allow technology to develop naturally to meet market needs rather than in a mandated fashion
- Capacity market design and Climate Leadership Plan provide the path forward; no further changes are needed to ensure Albertans are well served and investors are confident they can compete
- Procurement for paired DR&S and non-paired but aggregated renewable/storage should proceed as quickly as possible; also need standalone procurements for short-duration storage and long-duration bulk storage (minimum six hours)
- Any DR&S procurement must consider all technologies, avoid over-supply
- Essential to have realistic information on probable magnitude and cost of all long-term renewable electric power alternatives in order to plan Alberta’s power system long term
- Evaluation of DR&S must consider time of delivery and firm capacity value

### **Market**

- Storage, inerties and demand response are critical elements of a cost-optimized market
- Creating incentives via real-time price signals will create the competitive outcomes; contracting for renewables via auction process does not foster a fair, efficient, openly competitive market
- AESO should remain technology agnostic and allow economics/market forces to dictate outcomes; ‘pros’ of incenting otherwise uneconomic generation are far outweighed by ‘cons’ including distortion of price signals, undermining of market constructs, increased investor uncertainty
- Merchant power sales are not financeable; long-term offtake contracts are required whether asset is dispatchable or not

### **Generation**

- Hydro provides stable, long-term baseload at competitive cost, ramping ability and storage – this solution must not be ignored; need further study of development options for each of 60 sites identified in 2010 Hatch report (commissioned by Alberta Utilities Commission)
- Biomass has huge potential and should not be sidelined by other technologies
- Pumped storage will be much more expensive than wind/solar/battery alternatives in Alberta market
- Recommend investigating combined thermal-plus-storage systems
- Large-scale development of gas generation will eventually create legacy liabilities as DR&S technologies advance rapidly and displace them

### **Storage**

- Must ensure that storage projects can effectively unlock variety of value streams including: peak shifting, demand response, frequency/voltage regulation, capacity market
- AESO should consider piloting a grid-connected storage project to understand how it will behave in the Alberta context
- Storage is not immediately required for reliability, but market mechanisms should be established now as DR&S penetration increases
- AESO should host an energy storage symposium

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Appendix 4:  
Jurisdictional review report

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# **+** Role of Dispatchable Renewables in Renewable Energy Integration

**FINAL REPORT**

Prepared for AESO

March 23, 2018

Privileged and Confidential



- + Overview of Study and Findings**
- + Detailed Jurisdictional Comparison**
  - Selection of Comparable Jurisdictions
  - Jurisdiction Summaries
- + Key Takeaways from Jurisdictional Review**





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# OVERVIEW OF STUDY AND RENEWABLE INTEGRATION FINDINGS



# Study background

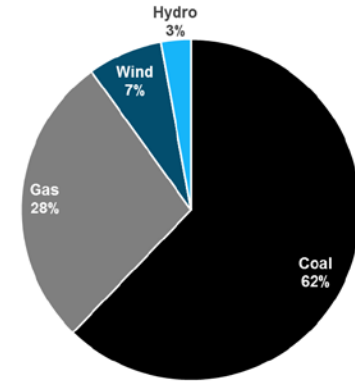
## + Alberta Electric System

- Currently 7% renewable energy share, targeting 30% by 2030 (likely high wind share) as coal capacity is retired
- Needs to anticipate potential integration challenges and solutions

## + E3 created a cross-jurisdictional comparison to highlight policies and practices other regions are using to address renewable integration challenges

- Covers 14 key electric systems in North America and worldwide with high renewable energy penetration
- Summarizes types of renewable integration challenges occurring or anticipated in those regions
- Identified policy support (if any) for particular integration solutions such as battery storage, pumped storage or other

Current AB Electric System



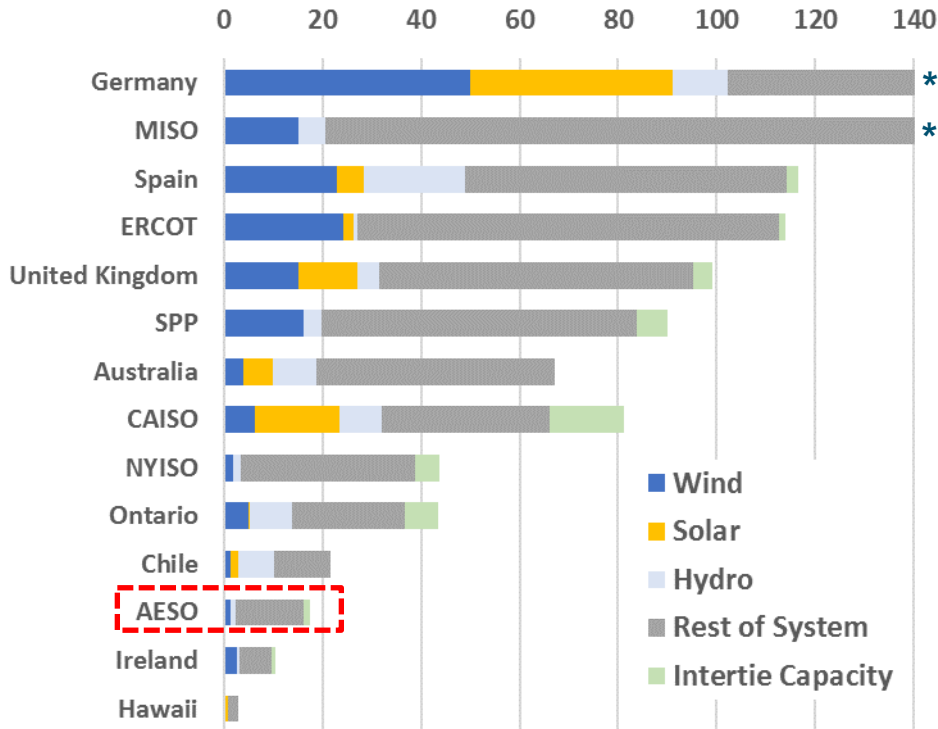
2016 Generation Mix  
Total Load: 79.6 TWh  
Peak Demand: 11.5 GW



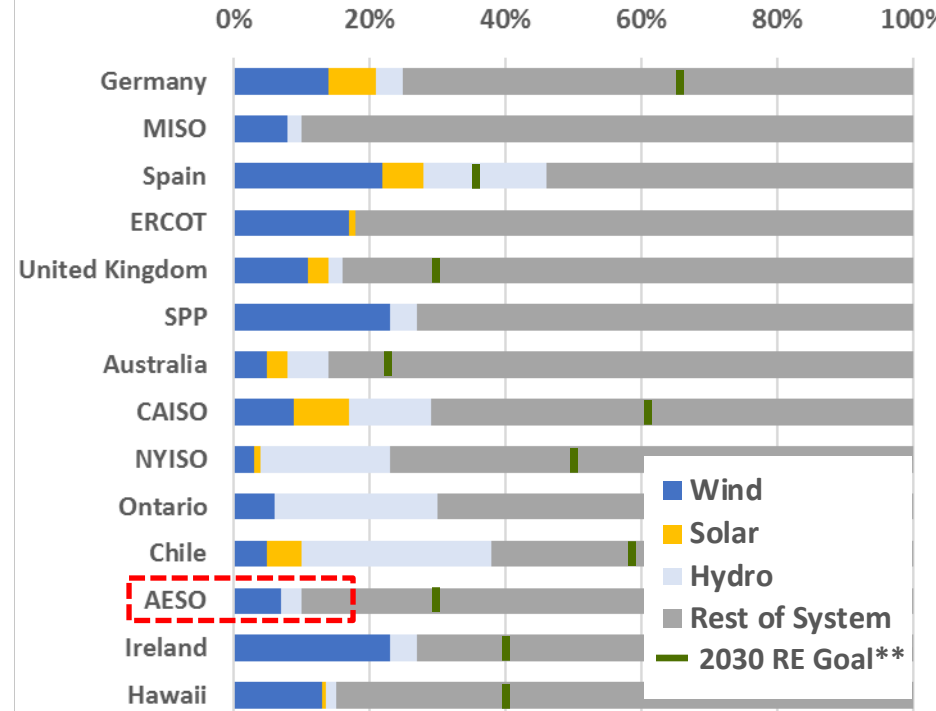


# Summary of selected jurisdictions for comparison of integration solutions

Nameplate Capacity (2016 GW)



Share of Energy Generation (2016 %)



*Selected systems are characterized by high wind penetration, low hydro capacity, and large coal retirements*

Notes: \*Germany total capacity = 204 GW, MISO total capacity = 180 GW  
 \*\*CA goal = RPS + hydro (not included in RPS). Chile goal of 60% is for 2035  
 Many jurisdiction RE goals are for 2020 and likely to be increased for 2030



# Key Implications from jurisdictional review

- + **Types of renewable integration challenges vary greatly by region**
  - Deliverability constraints (local transmission), system flexibility and ramping constraints, overgeneration and curtailment
- + **Many system factors contribute to when (what wind & solar %) integration challenges increase**
  - Types of renewable resource (wind, solar, diversified), size of system, import and export capability with flexible neighbors, flexible capacity (including hydro)
- + **Storage is one of many tools jurisdictions use to integrate higher levels of renewable generation**
  - A least-cost effort to integrate renewables relies on a combination of many of these tools
  - Before reaching very high renewable levels (>30% RPS) many solutions don't require large capital investments
- + **Direct policy mandate is one of a range of tools to encourage storage (or other integration solutions)**
  - Emphasized in CA and NY as attempt to support "market transformation" and long term cost reduction
  - Other options focused on supporting comparable valuation for storage and conventional resources (e.g., duration required for capacity or AS provision, high value for fast ramping)



# Many options available to provide upward or downward dispatch flexibility and support renewable integration

Increasing typical cost of Solution  
(at current technology cost)

Type of Solution	Upward Dispatch Options [need: serve load when wind ramps down quickly or unexpectedly]	Downward Dispatch Options [need: avoid curtailment if wind ramps up quickly or unexpectedly]
<b>Regional Coordination</b>	<b>Increased imports</b> via purchases over existing interties with neighboring systems	<b>Increased exports</b> via sales over existing interties with neighboring systems
<b>Load Adjustments</b>	<b>Time of use rates</b> to shift load away from high need hours	<b>Time of use rates</b> to shift load toward high wind output hours (if predictable)
	<b>Conventional demand response [DR]</b> (load shedding/curtailment)	<b>Flexible loads &amp; Advanced DR</b> (shaping load toward hours with high wind and solar)
<b>Renewable Generation Procurement &amp; Dispatch</b>	<b>Subhourly renewable dispatch</b> – pre-curtail to allow thermal gen to ramp up over a longer horizon	<b>Subhourly renewable dispatch</b> – curtail, and also let renewables provide downward reserves
	<b>Renewable portfolio diversity (by site location or technology)</b> - Avoids curtailment by spreading RE production over more hours of the year	<b>Renewable portfolio diversity</b> – reduce size of ramps and forecast uncertainty by procuring renewables resources with less correlated output
<b>Conventional Resource Procurement &amp; Dispatch</b>	<b>Reserve products</b> – market design to incent and hold fast ramping generation	<b>Market reserve products for flexibility</b> – to provide planned downward ramp
	<b>Additional hydro dispatch</b> – or adjustments to make more flexible ramp	<b>Additional hydro dispatch</b> – or adjustments to reduce minimum level
	<b>Flexible thermal resources</b> – with faster ramp and start times	<b>Flexible thermal resources</b> – with faster start times and lower min output (Pmin)
<b>Storage Solutions</b>	<b>Battery storage</b> – if shorter duration needed, or to provide reserves	<b>Battery storage</b>
	<b>Pumped storage or CAES</b> – if long-duration needed	<b>Pumped storage or CAES</b> – if long-duration needed for significant curtailment



# Policies to support storage as a particular integration solution

## + Jurisdictions with policy mandate for pumped hydro:

*(None surveyed)*

## + Jurisdictions with policy mandate for storage (multi-technology):

California

New York (pending)

## + Jurisdictions with market designs to enable storage to provide value:

California  
(flex capacity, AS design)

PJM  
(Regulation B)

ERCOT  
(Fast Response)

Others Jurisdictions  
...

*Many policies can be designed to support the value that storage provides without a direct mandate for MW of capacity*



# Economic curtailment policies can best leverage renewable assets

- + Curtailment is both a grid management tool and a measure of system efficiency**
  - Curtailment provides value by relieving congestion or overgeneration, but has associated opportunity costs and should be minimized by efficient market design and operations
- + Priority dispatch promotes renewable generation by guaranteeing output and revenues, but creates inefficiencies as renewable penetration grows**
  - Greater renewables deployment increases intermittency, overgeneration, and need for dispatch down
  - With priority dispatch, plants may be curtailed pro rata or based on age, technical constraints, economics, etc.
  - Economic curtailment minimizes dispatch down costs, allows better automation and responsiveness
- + Global movement towards economic curtailment to manage dispatch-down needs**
  - MISO switched to economic dispatch in 2011 via Dispatchable Intermittent Resource (DIR) tariff
  - Ontario removed priority dispatch in September 2013, allowing economic curtailment of wind
  - SPP began transition to economic dispatch in 2014 (part of new “Integrated Marketplace”)
  - European Parliament voted in February 2018 to phase out priority dispatch for new renewables after 2020
- + Compensation for curtailed production and sharing of curtailment risk takes many forms**
  - Compensation can be provided for fractional or full amount of value forgone by generator
    - Energy value (e.g. 80% of day-ahead market prices, forgone PPA price, etc.), incentive value (e.g. feed-in-tariff))
  - Uncompensated curtailment can be capped by generation or hours
    - California: many contracts cap uncompensated curtailment at share of generation (e.g. 5% of generation)
    - Alberta (latest RFP): compensated at 100% of PPA price for curtailment over 200 hrs/yr due to Tx constraints



# Summary of curtailment practices

*Prioritize renewables at higher system costs*

Jurisdiction	Dispatch	Guaranteed curtailment compensation
Germany	Priority	95% of day-ahead market value
Australia	Priority	Mixed
Spain	Priority	None for scheduled curtailment, 15% of day-ahead market value for real-time curtailment
Ireland	Priority	None as of 2018
California	Economic	Depends on contract, often capped at ~5% of generation
UK	Economic	Depends on contract
Ontario	Economic	Depends on contract
MISO	Economic	Depends on contract
New York	Economic	None
SPP	Economic	None
ERCOT	Economic	None

*Curtail renewables to minimize system costs*





# New market designs can promote and enable more flexible operation

## + Flexible capacity (hours)

- **CAISO:** Flexible Resource Adequacy product ensures long-term needs for flexible capacity are met. Product specifications for weekly starts, 4-hour ramp, etc. are met by all gas plants today, but may become more stringent in future

## + Ramping margin (minutes)

- **MISO:** Ramp Capability Product launched in 2016: payment for capacity (MW) available to ramp up or down within 10 minutes to meet forecasted change in net load. Product shifts market away from least-cost dispatch in present to avoid potential price spikes from ramping constraints in near future
- **CAISO:** Flexible Ramping Product implemented in 2016 at 5- and 15-minute intervals
- **SPP and NYISO:** evaluating similar ramping products
  - NYISO: "A generation ramp product that considers conditions 30 minutes or an hour ahead could hold a portion of wholesale generating capability aside to prepare for sharp, un-forecasted swings in load ramp net of renewable resource generation"

## + Rapid ancillary services (seconds or less)

- **Ireland's DS3** program will increase number of services from 7 to 14. New services include Fast Frequency Response and Dynamic Reactive Response
- **ERCOT:** Fast Frequency Response provides automated response within 30 cycles (~0.5 second)



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# SELECTION OF COMPARABLE JURISDICTIONS





# Selection of jurisdictions relevant to Alberta's goal of 30% by 2030

- + E3 selected jurisdictions with the greatest RE integration challenges**
  - High RE deployment to date with greater future targets (RE or GHG)
  - High reliance on intermittent types of RE (wind or solar)
- + Ruled out: jurisdictions with single-resource solution to renewables integration (e.g. majority hydro)**
  - Hydro provides majority of RE and/or balancing needs in Norway, Iceland, Uruguay, Costa Rica, the Pacific Northwest, etc.
- + Noted systems with similar sizes or generation mix and transmission inertia level as AESO**



# Selected jurisdictions most relevant to AESO's integration challenges

## + US systems

- California
- Electric Reliability Council of Texas (ERCOT)
- Midcontinent Independent System Operator (MISO)
- Southwest Power Pool (SPP)
- New York Independent System Operator (NYISO)
- Hawai'i

## + Canadian systems

- Ontario

## + Other countries

- Germany
- Spain
- UK
- Ireland
- Australia
- Chile

*Selected systems are characterized by high wind penetration, low hydro capacity, and large coal retirements*



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# JURISDICTION SUMMARIES



# Jurisdictional review criteria

- + E3 gathered information on the key characteristics of each jurisdiction's energy system**
  - Generation resource portfolio
  - Current and projected renewable capacity
  - Storage deployment and incentives
  - Grid challenges due to increased renewables
  - Policy initiatives that support RE integration
  - Market mechanisms that support RE integration
  - Overgeneration options: use of curtailment, storage capacity, and export capacity



# Summary of RE integration metrics for all jurisdictions

Jurisdiction	Dominant RE regime	RE gen% 2016 (2030 goal)	Peak hourly RE share (% of load)	Peak hourly RE (MW)	Peak hourly curtailment (MW)	Curtailment (% annual energy)	Storage (MW)	Import/export capacity (MW)	Primary challenge	Primary solution
California	Solar	36%* (62%)*	72%	15,000+	3,500	0.9%	4,200+	15,000	Overgeneration	Curtailment
ERCOT	Wind	18% (n/a)	54%	17,400	1,000 MW	3%–4%	70	1,100	Tx congestion	Tx upgrade, market redesign
MISO	Wind	10% (n/a)	24%	13,600	~500–1,300	0.3%	2,530	14,000 in / 8,000 out w/ PJM alone	Tx congestion	New Tx
SPP	Wind	27% (n/a)	54%	12,078	2,000	< 1%	475	1,200	Tx congestion	Tx upgrade
New York	Wind	23% (50%*)	32%	7,700	unknown	0.85%	2,240	5,000	Transmission congestion	Tx upgrade
Hawaii	BTM solar	25.8%	Oahu: 35% Maui: 72%	unknown	unknown	Oahu: 0.27% Maui: 5.5%	35+	None	Overgeneration	Curtailment
Ontario	Hydro and Wind	33.1%	unknown	unknown	unknown	5.66% surplus baseload gen	224+	6,600+	Overgeneration	Dispatch down VRE
Germany	Wind and Solar	29.5% (65%)	85%	55,000	1,580	1.2%	7,200	20,000	Overgeneration and ramping	Curtailment and flexible coal & nuclear
Spain	Wind, increasingly solar	36% (35%)	~70%	17,000+	unknown	5%	8,000	5,700	Overgeneration	Increased interconnection
United Kingdom	Wind	25% (N/A)	54%	19,300	unknown	4.1%	2,900	4,000+	Tx congestion, overgeneration	Curtailment
Ireland	Wind	26% (40%)	~60%	2,815	est. 500 MW	3.2%	302	1,000	Tx congestion, grid stability	Curtailment, new Tx, market reform
Australia	Wind, BTM solar	16% (23.5%)	unknown	unknown	unknown	Unknown	1,900	None	Congestion, overgeneration	Curtailment, demand response
Chile	Wind and Solar	16.3% (20%)*	31-42%	4,610	unknown	>2%	60	200	Transmission congestion	Tx upgrade



# California

## + Current and projected renewable energy deployment

- High solar and wind capacity (10 GW utility-scale solar, 6 GW BTM solar, 6 GW wind)
- Goal of 50% RE by 2030, likely to be increased to 100% by 2050
- Likely to meet goals with additional solar, up to 40 GW total by 2030

## + Storage deployment

- 4,000 MW of pumped storage hydro capacity statewide, primarily legacy plants
  - Castaic: 1,623 MW (COD 1973) tied to major aqueduct and reservoirs for LA water management
  - Helms: 1,212 MW (COD 1984) used as source of flexibility for Diablo Canyon nuclear plant
- Storage mandate: 1,325 MW of energy storage by 2020 (no large pumped hydro)

## + Grid challenges

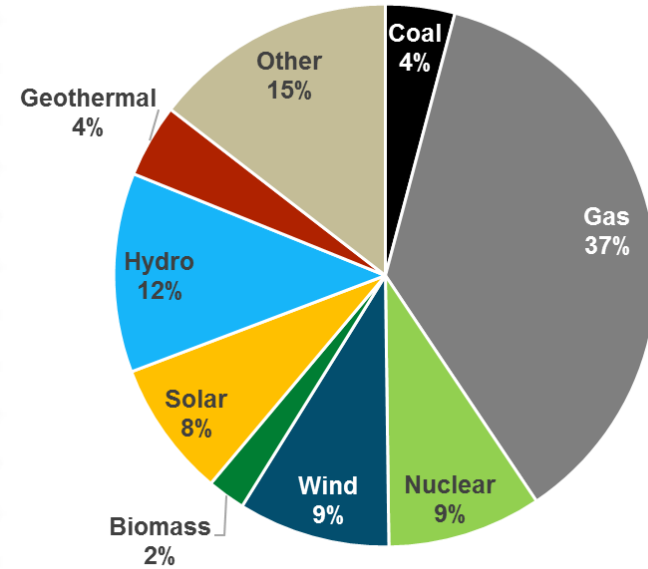
- Midday overgeneration and curtailment around midday solar peak
- Steep ramping requirements to meet early evening peak load as solar declines

## + Policy initiatives that support RE integration

- Storage mandate has led to battery storage deployment and may increase in future
- IOUs required to participate in demand response auction mechanism: 200 MW procured in 2017, growing in scale each year with BTM battery storage bidding as a DR resource

## + Market mechanisms that support RE integration

- Economic curtailment. Max to date: 3,500 MW in March 2017
- Reform of flexible capacity market underway (proposed increases in ramping and cycling requirements)
- Flexible ramping product implemented at 15- and 5-minute intervals in Nov. 2016



2016 Energy Mix  
Total Load: 291 TWh  
Peak Demand: 46.2 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
California	Solar	36%* (62%)*	72%	15,000+	3,500	0.9%	4,200+	15,000	Overgeneration	Economic curtailment

\* Hydro is not part of California RPS, but is included and held constant at current levels for comparison





## + Current and projected renewable energy deployment

- Currently 21 GW of wind, just 556 MW of utility-scale solar, 500 MW of hydro
- Interconnection queues: 8,500 MW wind, 2,000 MW solar; 4,200 MW of coal to retire by 2018
- State RE targets achieved and surpassed; wind increasingly economic as merchant generation

## + Storage deployment

- No pumped storage; 317 MW CAES project (Bethel Energy Center) approved, expected COD 2020
- No storage mandate but >50 MW battery storage installed in 2017 alone; 600 MW in interconnection queue

## + Grid challenges

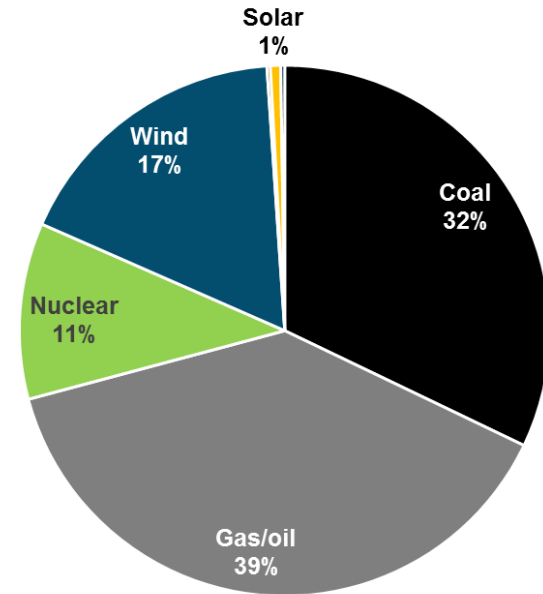
- Two main congestion constraints: import from North Texas to Houston area and export from the Panhandle region. Plans for \$6.1 billion of transmission investment between 2018 and 2023
- Wind unpredictability: Improved forecasting of ‘wind ramps’ using ELRAS (ERCOT Large Ramp Alert System) – Warns about large ramps 6 hrs ahead; Wind curtailment in spring and winter (up to 1,000 MW)

## + Policy initiatives that support RE integration

- Wholesale storage is exempt from transmission service rates (PUC Rule 25.192)
- Distributed Resource Energy and Ancillaries Market (DREAM) Task Force created to identify how solar PV, batteries, DR and other DER could participate in ERCOT energy market. Recommendations include aggregation and increased market participation and controls for distributed resources
- Competitive Renewable Energy Zone (CREZ) program led to development of new transmission for 18.5 GW of total wind capacity in 2013-2014 at a cost of approximately \$6.8 billion, helping reduce wind curtailment from 17% in 2009 to 4% in 2013

## + Market mechanisms that support RE integration

- Economic dispatch and curtailment for renewables
- NPRR 581 (2013) – Created a new ancillary service subset of Regulation Service known as Fast Responding Regulation Service (Fast Frequency Response)



2017 Energy Mix  
 Total Load: 357.4 TWh  
 Peak Demand: 69.5 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
ERCOT	Wind	18% (n/a)	54%	17,400	1,000	3%–4%	70	1,100	Tx congestion, curtailment	Tx upgrade, market redesign



## + Current and projected renewable energy deployment

- Currently ~15 GW of wind, minimal solar (first 100 MW integrated in 2017)
- 58.8 GW in interconnection queue, almost 80% renewable: 31 GW of wind, 16 GW of solar
- RE targets achieved and surpassed; wind deployment now driven by economics

## + Storage deployment

- Two pumped storage facilities make up a majority of the storage in MISO
  - Taum Sauk: 440 MW, COD in 1963
  - Ludington Pumped Storage Facility: 2,061 MW, COD in 1973
- No policy mandates for new storage, but 140 MW of battery storage has requested interconnection

## + Grid challenges

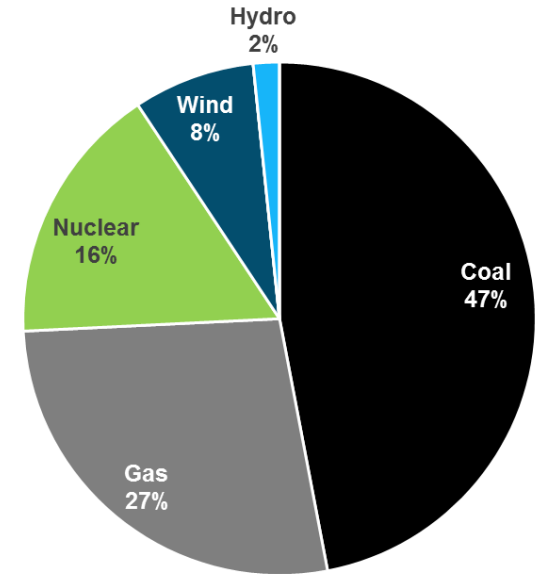
- Congestion from high wind penetration in northwest MISO away from load centers farther east and south. Difficulty building new transmission in certain states (e.g. Missouri) to alleviate congestion

## + Policy initiatives that support RE integration

- MISO continuing to develop definition for storage and rules for storage's participation in markets. Under pressure from stakeholders to accelerate process

## + Market mechanisms that support RE integration

- Dispatchable Intermittent Resource (DIR) protocol launched in 2011 switched MISO from manual curtailment to economic curtailment. Requires wind plants to bid into real-time market and automates dispatch down (curtailment)



2016 Energy Mix  
 Total Load: 615 TWh  
 Peak Demand: 112 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
MISO	Wind	10% (none)	24%	13,600	~500–1,300	0.3%	2,530	14,000 in / 8,000 out with PJM alone	Tx congestion	New Tx





## + Current and projected renewable energy deployment

- >16 GW installed wind capacity, minimal solar
- 95% of active interconnection requests are renewable: 77 GW wind and 17 GW solar
- Minimal RE targets: SPP states have exceeded RPS goals, wind development driven by low costs

## + Storage deployment

- Three pumped storage projects: Salina (260 MW, COD 1968), Truman (186 MW, COD 1979), Clarence Cannon (31 MW, COD 1984)
- Gregory County 800 MW pumped storage project discussed for decades, still seeking permits
- No policy mandates, but 840 MW of battery storage interconnection request

## + Grid challenges

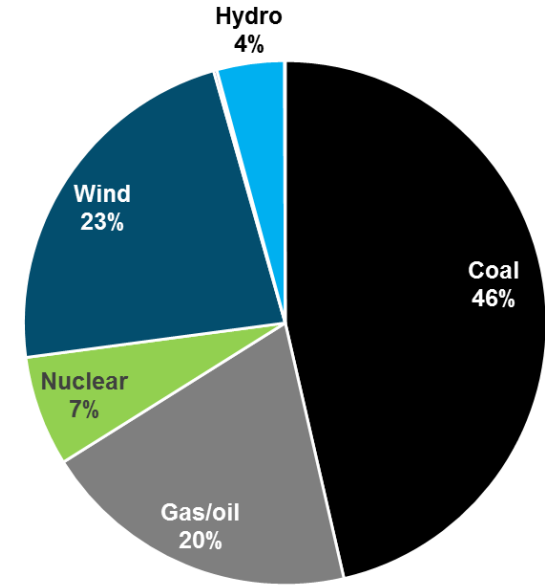
- Transmission congestion between wind in west and load in the east , alleviated by high Tx investments (\$8 bn in the last decade)
- Reliability study found minimal curtailment at 30% wind, but major curtailment as wind increases to 45% and 60% penetration. Peak curtailment as high as 5 GW in 60% scenario

## + Policy initiatives that affect RE integration

- SPP Wind Integration Task Force Wind Integration Study in 2010 and in 2016 led to major transmission reinforcements and market developments
- Limited capacity market: Use of reliability must run (RMR) plants for capacity to maintain resource adequacy compensated at their bid price

## + Market mechanisms that support RE integration

- Launched new "Integrated Marketplace" in 2014 to combine separate balancing areas into single SPP balancing authority. Moved from priority dispatch to economic dispatch and increased automation and controls for renewables



2017 Energy Mix  
 2016 Total Load: 253 TWh  
 2016 Peak Demand: 50.6 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
SPP	Wind	27%	54.2%	12,078	2,000	< 1%	475	1,200	Tx congestion	Tx upgrade



# New York

## + Current and projected renewable energy deployment

- Currently, 1,740 MW of installed wind, 32 MW of installed solar and 4,250 MW of hydro
- Clean energy standard (CES): 50% RE by 2030
- Mandate for 2,400 MW of offshore wind power by 2030

## + Storage deployment

- Existing 1,407 MW pumped hydro; 240 MW more proposed
- Upcoming mandate for 1,500 MW of storage by 2025; NYSERDA developing 2030 roadmap

## + Grid challenges

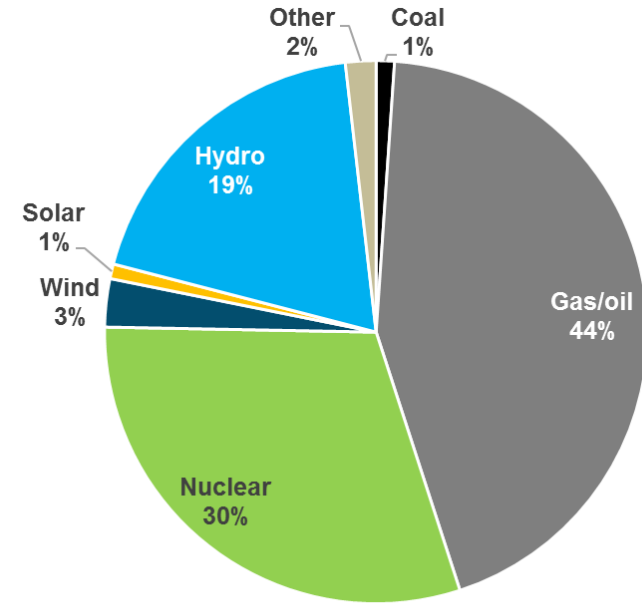
- Major congestion between renewable resources upstate and high demand in load centers downstate with limited ability to build new transmission capacity
- Lack of natural gas pipelines; Strong anti-pipeline political view

## + Policy initiatives that support RE integration

- NY REV (Reforming the Energy Vision) places strong focus on distributed resources, storage, demand response, rate reform, etc. to make grid more flexible on distribution side
- Storage and offshore wind mandates are being used to promote resource diversity, create jobs, and encourage market development

## + Market mechanisms that support RE integration

- Coordinated transaction scheduling (CTS) with PJM since 2014 – Reduces uneconomic flows across RTO borders by allowing traders to submit ‘price differential’ bids that would clear when the price difference between the regions exceeds a threshold



2016 Energy Mix  
 Total Load: 159.2 TWh  
 Peak Demand: 33.2 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
New York	Wind	23% (50%*)	32%	7,700 MW	unknown	0.85%	2,240 MW	5,000 MW	Transmission congestion	Tx upgrade

\* 50% target includes imports from Canada and New England



# Hawaii

Jurisdiction of Hawaiian Electric Companies only (excludes Kauai)

## + Current and projected renewable energy deployment

- 543 MW rooftop solar (out of 991 MW RE capacity) in 2016
- By 2021, planned addition of: 326 MW DG-PV, 31 MW Feed-in-Tariff solar, 115 MW DR, 360 MW grid-scale PV, 157 MW grid-scale wind

## + Storage deployment

- 17 planned projects currently exist, totaling over 90 MW of grid scale storage
- “Smart Export” program for BTM PV + storage systems, allowing customers to export power to the grid at night for credit (35 MW program cap)

## + Grid challenges

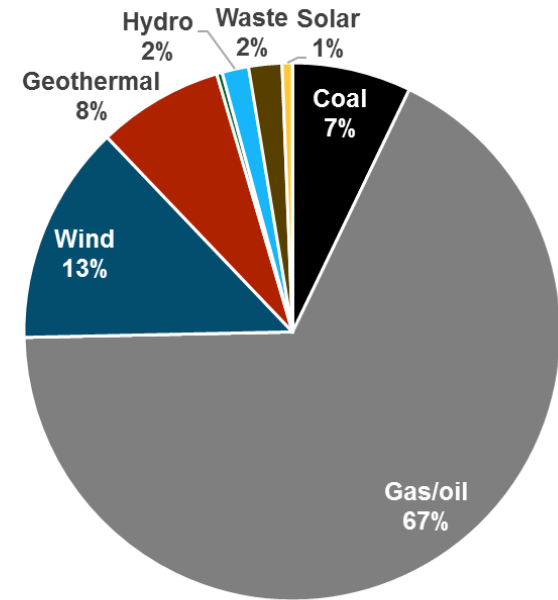
- Small, intra-island networks with limited grid hosting capabilities

## + Policy initiatives that support RE integration

- Release of NEM successor programs (implemented minimum charge fee and limits on export credit)
- Integrated Grid Planning detailing near-term action plan to achieve RPS targets, including:
  - Evaluation of an interisland transmission network
  - Distribution grid improvements to increase hosting capacity
  - Smart Grid upgrades to enable two-way communication and appliance control

## + Market mechanisms that support RE integration

- Development of new contracting methods to move away from renewables as “must-take”
- Pilot TOU rate studies and possible adoption in future



2016 Energy Mix  
 Total Load: 8.9 TWh  
 Peak Demand: 1.2 GW (Oahu)  
 188 MW (Hawaii)  
 201 MW (Maui)

Jurisdiction	Dominant RE Regime	RE % 2016	Peak PV & Wind (% system peak, 2015-2016)	Curtailment (% of RE) 2016	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Hawaii	BTM solar	25.8%	Oahu: 35% Maui: 72%	Oahu: 0.27% Maui: 5.5%	>35 MW	None	Overgeneration	Curtailment



## + Current and projected renewable energy deployment

- Already >90% of electricity is carbon-free (only about 7% VRE)
- Behind the meter: additional 2 GW of distributed solar, 0.6 GW of distributed wind

## + Storage deployment

- 400 MW of existing pumped storage
- 2017 RFP for storage for regulation reserves selected two battery storage projects (55 MW). 2014 RFP selected 14 projects (50 MW), mostly lithium-ion battery but also flow battery, flywheel, compressed air, etc.

## + Grid challenges

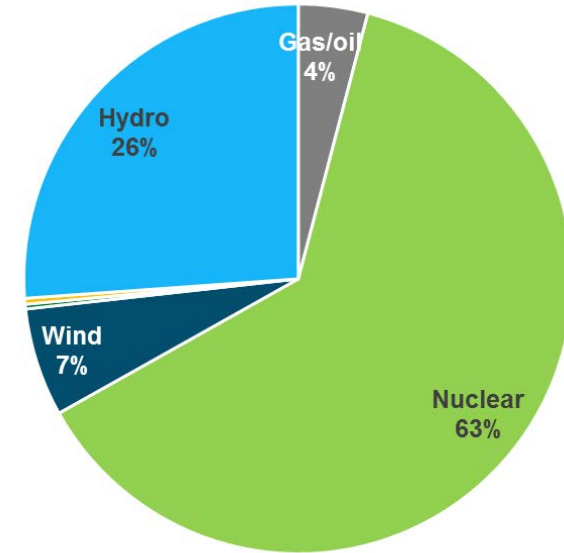
- Curtailment: “Dispatch down wind”, spilled hydro, nuclear reductions

## + Policy initiatives that support RE integration

- Flexible load initiatives: DR goal of 10% by 2025, Demand Response Auctions (570 MW summer/ 712 MW winter peak), AGC-controlled Dispatchable Loads (AS and energy wholesale markets), TOU Rates
- Grid-LDC coordination initiative (data sharing and enhanced reliability)
- Renewable Integration Initiative (centralized forecasting and dispatchable VRE)
- Flex nuclear: 8 units at Bruce Power can dispatch down 300 MW each via condenser steam discharge, allowing cheaper curtailment than renewable PPA prices

## + Market mechanisms that support RE integration

- Move from priority dispatch to economic dispatch for renewable generation
- “Market Renewal” program: movement to more frequent intertie scheduling and market product improvements to value flexibility, ramping, etc. in AS market



2017 Energy Mix  
 2017 Total Load: 132.7 TWh  
 2016 Peak Demand: 23.21 GW

Jurisdiction	Dominant RE Regime	RE % 2017 (2025 goal)	Peak ZE (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Ontario	Hydro & Wind	33.1%	>100%	unknown	unknown	5.66%* (SBG estimate)	>224	> 6600 MW	Surplus Baseload Generation (SBG)	Dispatch down VRE

\* Out of total load – 1.66% is dispatched down wind, 0.57% is reduced nuclear and 3.43% is lost hydro



# Germany

## + Current and projected renewable energy deployment

- Over 50 GW installed wind, 5 GW offshore wind and 43 GW solar PV installed capacity
- Goal of 65% RE by 2030 and 100% RE by 2050
- Offshore wind targets: 7.6 GW by 2020 and as much as 26 GW by 2030

## + Storage deployment

- 67 MW of energy storage (128 MWh) as of 2015; 161 MW in 2016
- 6,800 MW of pumped storage in 2016; 200 MW project proposed

## + Grid challenges

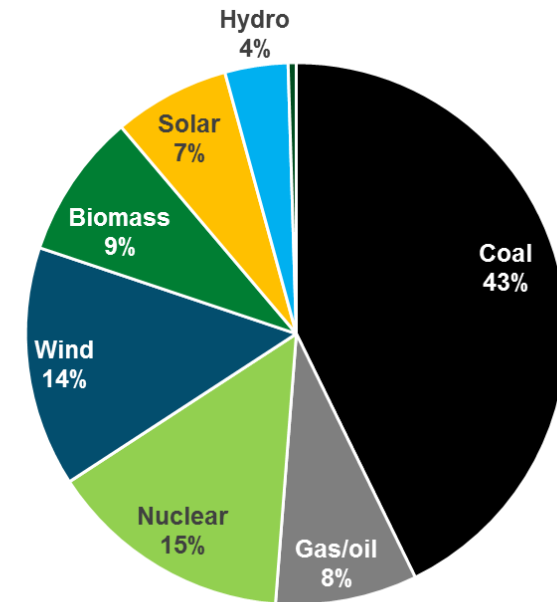
- Transmission congestion from power-producing North to industrial South
- Overgeneration during periods of high wind and solar. Reliance on must-run conventional generation to manage regulation down
- Difficulty exporting energy during overgeneration periods

## + Policy initiatives that support RE integration

- Future wind farms to be sited by the government (Centralized Danish model)
- Existing coal-fired plants to be retrofitted for flexible operations
- Load-following control in Nuclear PP (down to 50% of total capacity at a rate of up to 30 megawatts per minute without intervention) – Prohibited in the US

## + Market mechanisms that support RE integration

- Limited use of curtailment as integration tool. Priority dispatch of RE; curtailments compensated by 95% of DA Market price



2016 Energy Mix  
Total Load: 548 TWh  
Peak Demand: 83 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Germany	Wind and Solar	29.5% (65%)	85%	55,000	1,580	1.16%	7,200	20,000 MW*	Overgeneration and ramping	Curtailment and flexible coal & nuclear

\*Less than half of the intertie capacity has ever been utilized



# Spain

## + Current and projected renewable energy deployment

- Wind dominant system: 23 GW of wind capacity, 17 GW of hydro, and 7 GW of solar PV
- Solar growth is more recent: 2017 installations of 3,909 MW solar and 1,128 MW wind
- Goal of 20% of all energy to be renewable by 2020, already surpassed

## + Storage deployment

- Nearly 8 GW of pumped hydro storage. 5 GW legacy, 3+ GW new, more underway
  - La Muela 2,000 MW (2013), €1.2 billion
  - Aguayo II 1,000 MW expansion (2014), estimated €600 million
- Li-ion storage projects around 20 MW being developed

## + Grid challenges

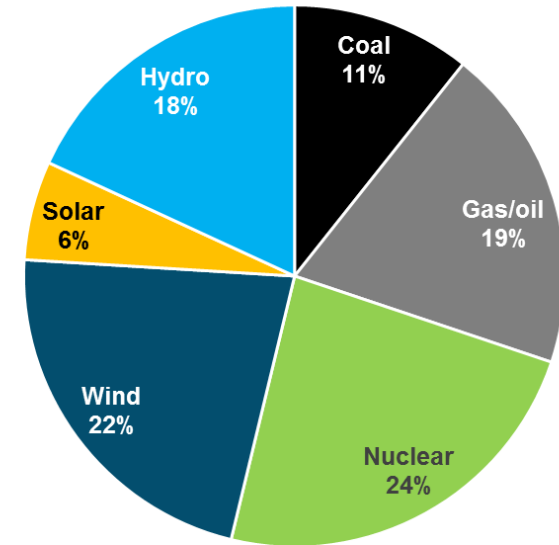
- Wind overgeneration and transmission congestion

## + Policy initiatives that support RE integration

- Renewables receive priority dispatch, but manual curtailment is managed day ahead based on relative bids. Curtailments compensated at 15% of DA price and can still participate in AS markets
- Control Center of Renewable Energies (CECRE) monitors and controls production from large RE facilities in real time
- Transmission expansion to increase export capacity: proposed DC interconnection with France of 5,000 MW exchange capacity- to start in 2025

## + Market mechanisms that support RE integration

- Rejected wind bids from day-ahead bids can still contribute to regulation up/down in reserves market



2016 Energy Mix  
 2017 Total Load: 262.6 TWh  
 2016 Peak Demand: 40.5 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Spain	Wind, increasingly solar	36%	~70%	17,000+	unknown	5%	8,000	5,700 MW	Overgeneration	Increased interconnection & export capacity





# United Kingdom

## + Current and projected renewable energy deployment

- Rapid shutdown of coal with much capacity converted to biomass
- Offshore wind makes up over 33% of 18+ GW in wind capacity
- Goal of 57% GHG reduction by 2032 and 80% by 2050 (1990 baseline)

## + Storage deployment

- 2,800 MW of pumped storage
- 60 MW of battery storage today, plus approximately 500 MW under development to serve capacity contracts starting in 2020

## + Grid challenges

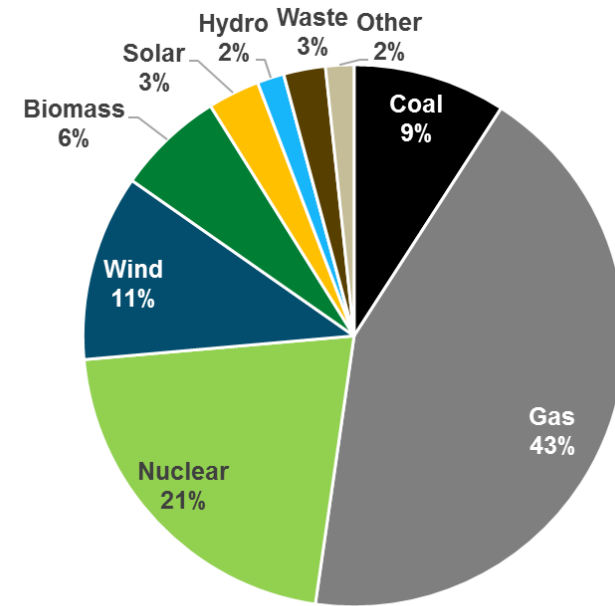
- Large wind deployment in Scotland with transmission constraints to loads in south. Western Link HVDC subsea transmission line with 2,200 MW capacity, due in 2018, should relieve constraint temporarily
- Historical curtailment policy was costly, reformed in 2017 to prevent costly PPA payments during overgeneration hours

## + Policy initiatives that support RE integration

- Increased transmission buildout within UK and to neighbors. 1 GW lines to Belgium and France due online in 2019

## + Market mechanisms that support RE integration

- Economic curtailment, capacity market with long-term contracts
- Reform of ancillary services and flexible capacity markets to allow energy storage to better monetize different types of value it provides



2016 Energy Mix  
Total Load: 336 TWh  
Peak Demand: 50.6 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
United Kingdom	Wind	25% (N/A)	54%	19,300	unknown	4.1%	2,900	4,000+ MW	Transmission, overgeneration	Curtailment

<http://www.ncl.ac.uk/media/wwwnclacuk/cesi/files/Intro%20to%20highRES%20model%20from%20wholeSEM%20-%20Dr%20Price%20-%20UCL.pdf>



# Ireland (incl. Northern Ireland)

## + Current and projected renewable energy deployment

- 40% RE by 2020
- 4,000+ MW of wind today, likely to exceed 2026 target of 5,000 MW
- Ireland: Up to 100 MW of solar by 2023. Northern Ireland: 80 MW solar currently, 250 MW in development

## + Storage deployment

- Single 292 MW pumped storage facility, commissioned in 1974
- Battery storage: 10 MW Kilroot Power Station pilot project is connected at transmission level, provides frequency regulation. Plan for 100 MW storage array next to Kilroot.
- Connection agreement for a new 70 MW facility
- 330 MW (out) / 250 MW (in) CAES project under discussion, no investment decision yet

## + Grid challenges

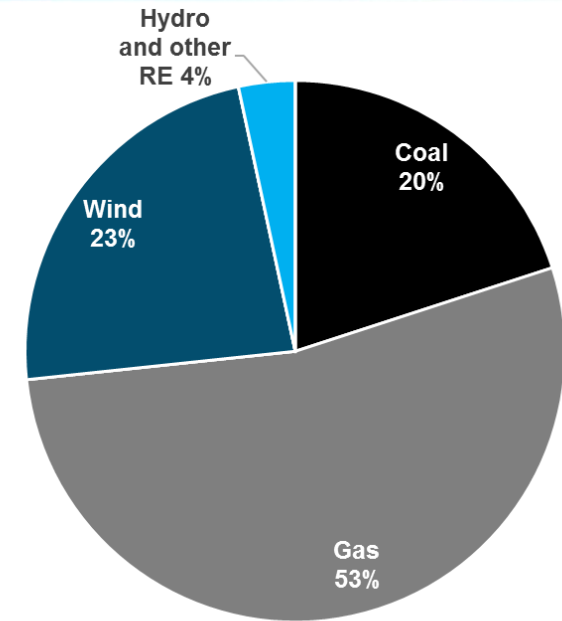
- Transmission congestion has led to significant curtailment of wind

## + Policy initiatives that support RE integration

- REFIT 3 provides an incentive for biomass-fired CHP

## + Market mechanisms that support RE integration

- Wind has priority dispatch with sequential curtailment tiers. SO has automatic controls
- Delivering a Secure, Sustainable Electric System (“DS3”) program has introduced new ancillary service products for inertia, fast frequency response, ramping margin (1-, 3-, and 8-hr), etc. to increase system’s maximum nonsynchronous capacity from 50% to 75% by 2020



2016 Energy Mix  
Total Load: 37.2 TWh  
Peak Demand: 6.8 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Ireland	Wind	26%	~60%	2,815	est. 500 MW	3.2%	302	1,000	Transmission capacity, grid stability	Curtailment, new Tx, market reform





# Australia

## + Current and projected renewable energy deployment

- >6 GW Hydro, 3 GW Wind; 42% target by 2030 – now abandoned
- Significant installation of BTM solar PV
- Most of the load and wind plants are located in South Australia (SA), Victoria and NSW
- South Australia (SA): committed to 80% RE by 2022. Currently 57% solar + wind, supported by strong interconnection with Victoria (Melbourne)

## + Grid challenges

- Flexibility and ancillary service constraints in SA due to priority dispatch of renewables and lack of synchronous generation: frequency deviations, frequency control AS
- In SA, wind constrained at 1,200 MW cap and export to Victoria limited to 250 MW

## + Storage deployment

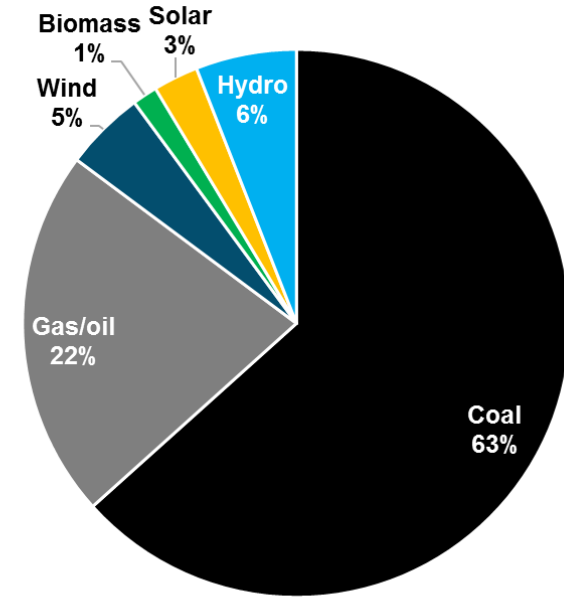
- 1,800 MW pumped storage
- 100 MW (129 MWh) in a single project by Tesla – the largest in the world – funded by the Australian government. Tesla to build another 20 MW battery system with wind farm

## + Policy initiatives that affect RE integration

- SA: Automatic Under Frequency Load Shedding (AUFLS): last resort safety net to prevent system collapse (initially started in New Zealand) – mandatory load shedding during non-credible contingency events; Designing an Over Frequency Generation Shedding (OFGS)

## + Market mechanisms that support RE integration

- Undergoing reform of ancillary services market to support frequency regulation issues



2017 Energy Mix  
 2016 Total Load: 257.3 TWh  
 2016 Peak Demand: 34.8 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2020 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Australia	Wind	16% (23.5%)	unknown	unknown	unknown	unknown	1,900	None	Congestion, overgeneration	Curtailment, demand response



## + Current and projected renewable energy deployment

- Currently 16.3% renewable (34% with hydro); ahead of schedule for 2025 goal

## + Storage deployment

- 60 MW installed mainly for frequency regulation and spinning reserves
- 110 MW CSP plant with 18 hour storage under construction
- Proposals for additional 710 MW of CSP and 300 MW Pumped hydro (Valhalla)

## + Grid challenges

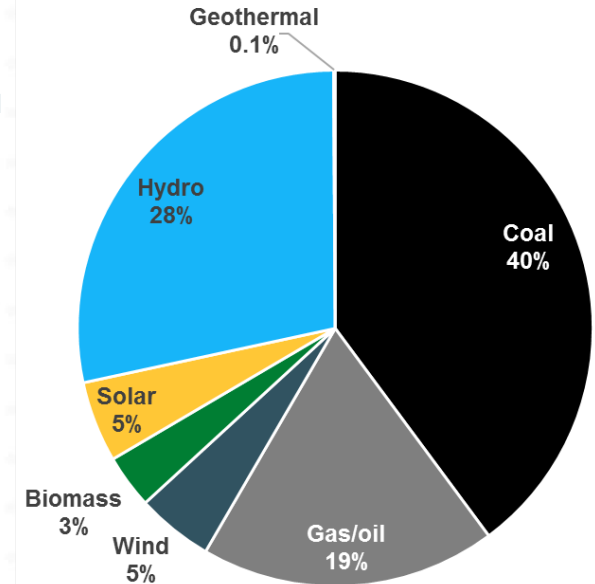
- Curtailment of resources due to transmission congestion
- Increased cycling in thermal facilities
- Expecting 0 \$/MWh prices by 2021-24 with potential duck curve due to solar
- Frequency regulation and other AS studies underway

## + Policy initiatives that support RE integration

- New centralized transmission planning function for ISO
- Ambitious Transmission Expansion Plan (over US\$ 1bn)
- International Interconnections

## + Market mechanisms that support RE integration

- Restructure of AS procurement and compensation mechanisms, RE auctions



2017 Energy Mix  
Total Load: 68.27 TWh  
Peak Demand: 10.4 GW

Jurisdiction	Dominant RE Regime	RE % 2017 (2025 goal)	Peak RE to date (% hourly)	Peak RE (MW)	Curtailment (Peak MW)	Curtailment (% Annual)	Storage (MW)	Import/Export Capacity (MW)	Primary challenge	Primary solution
Chile	Wind & Solar*	16.3% (20%)*	31-42%	4,610	Unknown	>2% (2016)	60 MW	200 MW	Transmission congestion	Tx upgrade

\* RE definition does not include large scale hydro



Energy+Environmental Economics

# KEY TAKEAWAYS FROM JURISDICTIONAL REVIEW



# Where Alberta stands today

## + Best comparables: high wind, low solar, low hydro, coal switching to gas

- Currently similar in RE penetration to MISO, Australia
- On long-term path similar to Ireland and SPP where wind is dominant RE resource

## + Renewable energy deployment and policies

- Currently 1,500 MW of wind capacity, 880 MW of hydro
- Round 1 of Renewable Energy Program (REP) procured nearly 600 MW of wind in 2017
- Rounds 2 and 3 announced February 2018, will procure additional 700 MW in 2018
- Target of additional 5,000 MW of renewable capacity by 2030

## + Storage deployment and policies

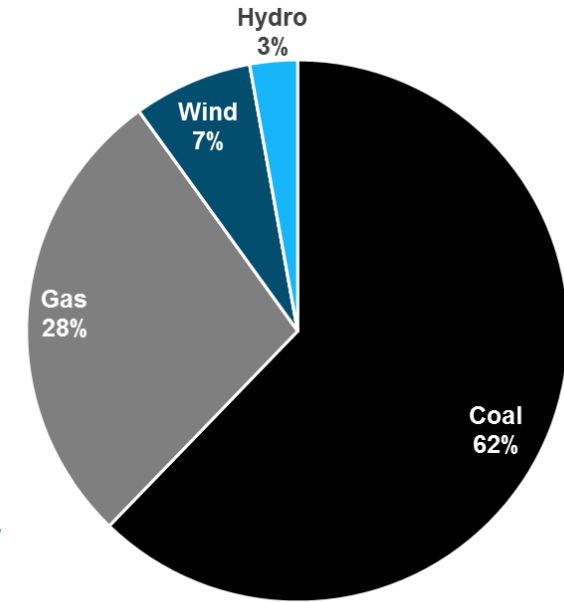
- No large transmission-scale storage projects
- 2015 AI-EES funding of \$1.5m for six storage project demonstrations: lithium-ion, fuel cell, flow battery, compressed air

## + Grid challenges

- New curtailment policy defined in latest Alberta RFP: risk sharing between wind owner and AESO. Unpaid curtailment due to Tx constraints capped at 200 hours, then paid by AESO
- Limited curtailment today: just two days in 2016 and 6 hours with curtailment

## + Balancing and reliability solutions

- Gas and hydro generation are greatest existing sources of flexibility
- Available export capacity increasing in recent years, nearly full availability
- Capacity market under development



2016 Generation Mix  
 Total Load: 79.6 TWh  
 Peak Demand: 11.5 GW

Jurisdiction	Dominant RE Regime	RE % 2016 (2030 goal)	Storage (MW)	Import/Export Capacity (MW)
Alberta	Wind	7% (30%)	<5	1,400



# Alberta tomorrow?

## + Increased wind deployment to meet 30% RE goal by 2030

- Potential increase in curtailment if:
  - a) Transmission congestion arises in areas with high wind buildout
  - b) Wind generation exceeds AESO demand and export capacity in certain hours
- More variable wholesale market dynamics with increased prevalence of zero prices

## + Increased coal to gas repowering

- Flexible gas likely to cycle more frequently
- New capacity market may help support gas generation as energy revenues decline

## + Potential for stricter GHG or RE goals after 2030

- At higher RE penetration, value of resource diversity and storage increases and different types of assets may become economical





# Common conclusions on integration of renewables

- + **Specific RE integration issues depend on complex interactions between load profile, generation profiles, and system capacity and transmission constraints**
  - For example, solar is more predictable than wind, but also more intermittent. Solar generation increases ramping needs more than wind generation
- + **In other jurisdictions, conventional generation and RE curtailment have been more cost-effective sources of flexibility than storage**
  - Flexibility ranking: hydro/pumped storage > gas > baseload coal, nuclear, geothermal, biomass
  - Wind and solar provide downward capacity flexibility in form of curtailment. Curtailment policy is important to implement correctly to balance RE value and costs
  - Energy storage is not widely deployed today, but may be increasingly valuable as RE penetration increases. Current policy is more focused on supportive market design and demonstration projects
    - Reforms to AS markets, allowing new forms of market participation (stacking capacity and AS contracts)
    - Locating storage together with RE adds flexibility. Practice is not widely used, but expected to become more common in jurisdictions with high curtailment risk (e.g. California)
- + **Transmission expansion plays a key role in RE integration and balancing**
  - Delivery from RE-rich regions to load pockets is a leading constraint in RE deployment
  - Greater intertie capacity with neighboring grids brings significant benefits from trading and balancing overgeneration, particularly if flexible hydro is available nearby



# Challenges of renewable energy integration

## + Delivery constraints

- Renewable resources often located away from loads, leading to congestion if buildout exceeds transmission capacity

## + System flexibility constraints

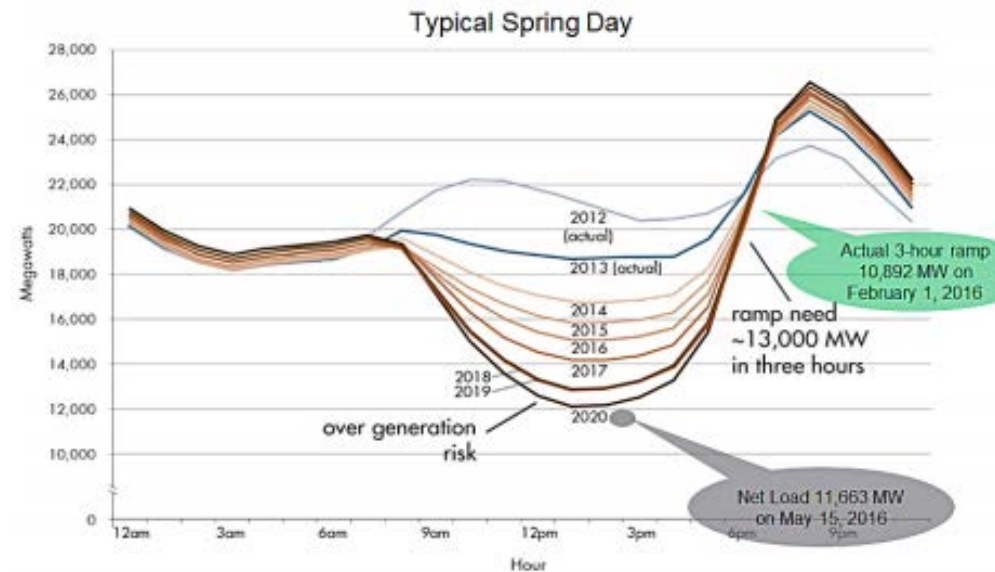
- Intermittent generation increases ramping needs

## + Overgeneration

- In certain hours, generation may exceed load

## + System reliability

- Capacity contribution of renewables is less certain, more difficult to quantify



California's infamous "duck curve" features midday solar overgeneration followed by steep ramping requirements for evening peak



# Key factors that enable or hinder jurisdictions' ability to integrate renewable generation

## + Type of renewable resources and penetration

- Wind, solar, and hydro present different integration needs
- Diversification creates valuable portfolio effects
- RE integration challenges scale non-linearly with market penetration

## + System characteristics

- Larger grid and increased import/export capacity provide advantages from diversification and trading
- Load profile may or may not coincide with renewable generation profile

## + Flexible capacity

- Dispatchable hydro, gas turbines, curtailable RE, energy storage, demand response, and enhanced coal/nuclear can all provide fast-ramping capacity

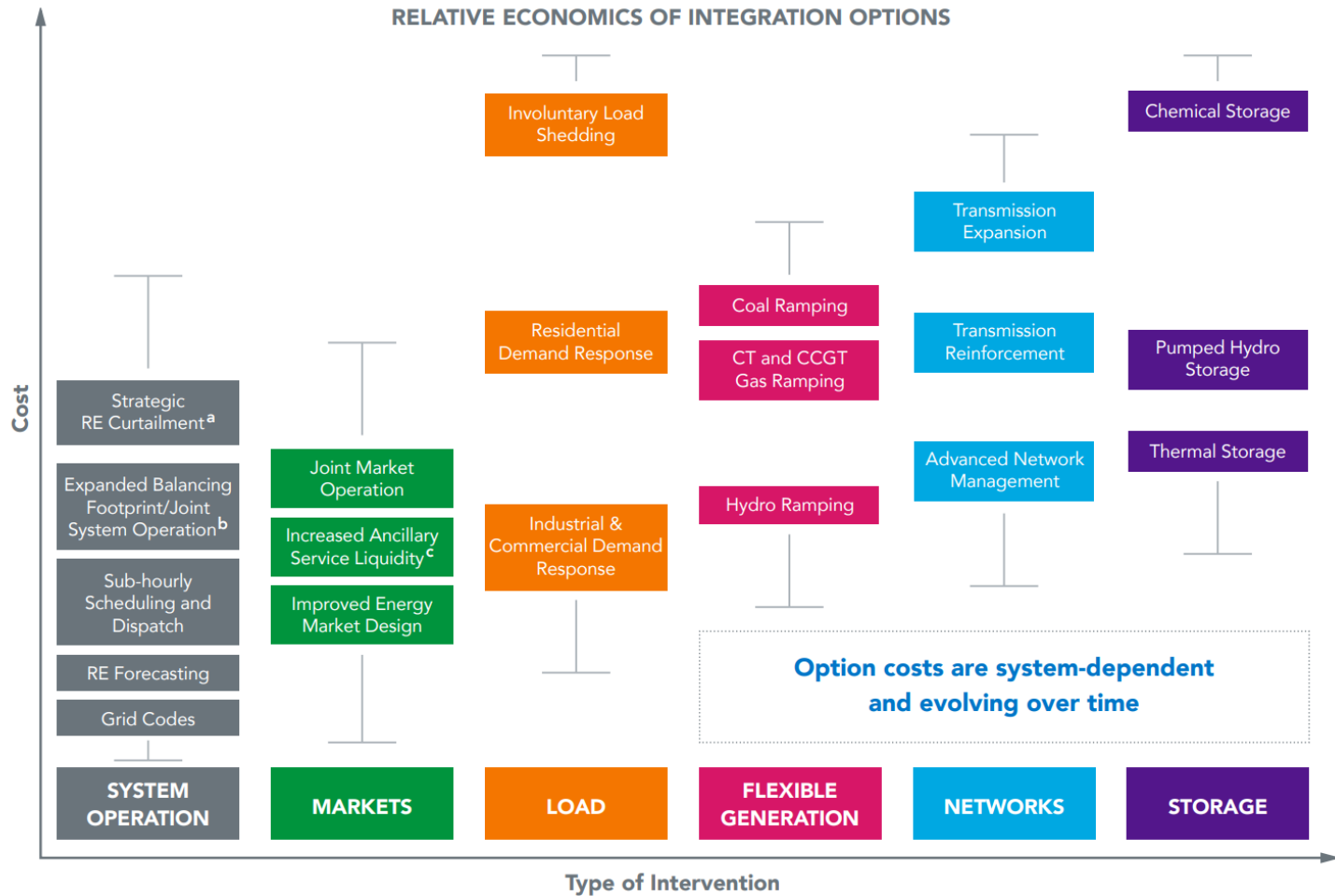
## + Energy storage

- Pumped storage, batteries, compressed air, etc. can absorb overgeneration





# RE integration options range from operational changes to new assets



*Optimizing market design and use of existing assets is more economic than large capital investments in new transmission or storage capacity*



# Most cost-effective solutions are generally least capital intensive

## + Delivery constraints

- Transmission planning is key to efficient RE integration

## + System flexibility constraints

- Increased cycling of existing flexible generation (hydro, gas) is cheapest way to meet ramping requirements
- Retrofit of existing baseload generation (coal, nuclear) may increase flexibility, value
  - Lower minimum unit output (Pmin), increased ramp rates, reduced start-stop times, etc.

## + Overgeneration

- At low levels, curtailment has minimal cost. Can also be used to minimize system ramping needs
- Exporting to neighboring grid is cheaper than building new storage capacity

## + System reliability

- RE integration has not significantly impacted reliability in jurisdictions analyzed
- Resource adequacy becomes much more costly as renewable penetration increases to high levels (e.g. California 100% RPS) and RE capacity value decreases



# Reframing the concept of “dispatchable” renewables

## + Different resources are dispatchable in different ways

- Hydro plants may be highly dispatchable or not at all depending on their physical characteristics (e.g. run-of-river vs. large reservoir)
- Geothermal or biomass may provide dispatchable renewable capacity, but only at high cost and in sub-optimal use cases (gas is more efficient for frequent cycling)
- Storage co-located with wind or solar can be used to make generation more dispatchable to extent allowed by storage capacity
- Curtailment or “dispatch down” can be used to give wind and solar the technical characteristics of dispatchable resources

## + Concept of dispatchability really concerns need for increased grid flexibility to support increased renewable generation

- Flexibility comes in many forms and can be provided by existing resources (e.g. hydro, gas), curtailment, exports, demand response, storage, etc.
- Different types of flexibility can be incentivized by different market designs: economic curtailment of RE, new ancillary services or flexible capacity markets, etc.

**Dispatchability**



***Flexibility***



# Many options available to provide upward or downward dispatch flexibility and support renewable integration

Increasing typical cost of Solution  
(at current technology cost)

<u>Type of Solution</u>	<b>Upward Dispatch Options</b> [need: serve load when wind ramps down quickly or unexpectedly]	<b>Downward Dispatch Options</b> [need: avoid curtailment if wind ramps up quickly or unexpectedly]
<b>Regional Coordination</b>	<b>Increased imports</b> via purchases over existing interties with neighboring systems	<b>Increased exports</b> via sales over existing interties with neighboring systems
<b>Load Adjustments</b>	<b>Time of use rates</b> to shift load away from high need hours	<b>Time of use rates</b> to shift load toward high wind output hours (if predictable)
	<b>Conventional demand response [DR]</b> (load shedding/curtailment)	<b>Flexible loads &amp; Advanced DR</b> (shaping load toward hours with high wind and solar)
<b>Renewable Generation Procurement &amp; Dispatch</b>	<b>Subhourly renewable dispatch</b> – pre-curtail to allow thermal gen to ramp up over a longer horizon	<b>Subhourly renewable dispatch</b> – curtail, and also let renewables provide downward reserves
	<b>Renewable portfolio diversity (by site location or technology)</b> - Avoids curtailment by spreading RE production over more hours of the year	<b>Renewable portfolio diversity</b> – reduce size of ramps and forecast uncertainty by procuring renewables resources with less correlated output
<b>Conventional Resource Procurement &amp; Dispatch</b>	<b>Reserve products</b> – market design to incent and hold fast ramping generation	<b>Market reserve products for flexibility</b> – to provide planned downward ramp
	<b>Additional hydro dispatch</b> – or adjustments to make more flexible ramp	<b>Additional hydro dispatch</b> – or adjustments to reduce minimum level
	<b>Flexible thermal resources</b> – with faster ramp and start times	<b>Flexible thermal resources</b> – with faster start times and lower Pmin
<b>Storage Solutions</b>	<b>Battery storage</b> – if shorter duration needed, or to provide reserves	<b>Battery storage</b>
	<b>Pumped storage or CAES</b> – if long-duration needed	<b>Pumped storage or CAES</b> – if long-duration needed for significant curtailment

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## Appendix 5:

### Dispatchable renewables: AESO analysis

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# Appendix 5: Dispatchable renewables: AESO analysis

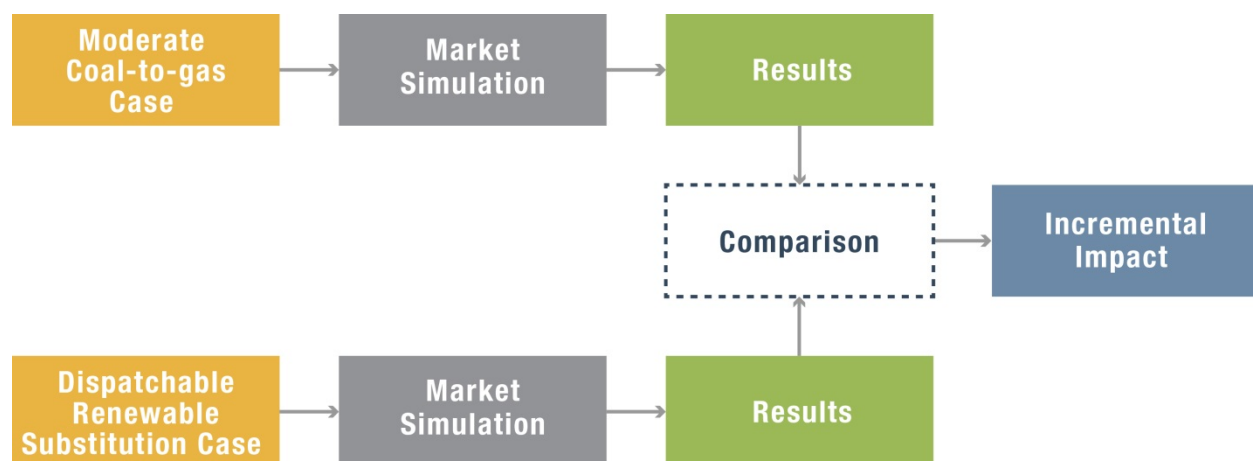
## Scenario Simulations via Substitution Analysis

The AESO conducted a comparative scenario analysis to assess incremental benefits and costs arising from replacing intermittent wind generation (a variable renewable generation resource) with various dispatchable renewables including biomass, geothermal, and run-of-river hydro generation. In essence, this analysis compares changes between an initial case (wind-dominant simulation) and a substitution case (mix between wind and dispatchable renewables simulation) to assess the incremental impact to each alternate scenario (see Figure 1).

*The AESO is using scenario simulations to perform comparative analysis, not to infer a particular future market outcome, but rather to test a range of possible outcomes.*

*This system-wide analysis relies on high-level assumptions. Individual projects would benefit from more refined, detailed information. However, this system-level analysis gives a directional indication of overall benefits or costs from the substitution.*

**Figure 1: Substitution analysis work flow**



## Key Inputs and Assumptions

### Moderate coal-to-gas conversion case (2018–MCTG)

For the initial case, the AESO developed a market-based scenario that assumes coal-to-gas conversions and other factors (e.g., natural gas prices, environmental regulations, and government policies) that are expected to occur, driven by market fundamentals over the study period (2021–2030). For the purposes of this report, the initial case is called the 2018 Moderate Coal-to-gas Conversion (2018–MCTG) Case. The 2018–MCTG Case uses the *AESO 2017 Long-term Outlook (2017 LTO) Reference Case* as a starting point, with some adjustments.

The AESO assessed the unsubsidized cost-competitiveness across technologies to determine a market-driven starting point for all generation types that may be added to the Alberta system. Similar to the 2017 LTO, results indicate that gas-fired generation is most viable on a merchant basis. Gas generation, when compared to renewable generation (wind, solar, biomass, hydro and geothermal), is more likely to recover

the returns required to justify its investment from capacity, energy and ancillary services markets over the study period. In light of this, wind and dispatchable renewables are added to all simulation scenarios by assuming they will be procured through an out-of-market, Renewable Electricity Program (REP)-like program.

The 2018-MCTG achieves provincial government-mandated renewable energy targets by 2030, with wind generation being the only renewable added to the system, besides 200 MW of solar capacity. This addition of 6,200 MW of wind capacity between 2019 and 2029 results in higher levels of intermittent renewable generation and therefore higher market price volatility. This enables assessing incremental impacts due to price volatility once wind is substituted with dispatchable renewables.

**Figure 2: Summary of assumptions and capacity build profile for 2018-MCTG**

Assumption	Description
Load Growth [Aligned with the AESO 2017 Long-term Outlook]	Average annual growth rate of 0.9 per cent until 2045
Natural Gas Prices (AECO – C; 2017\$)	\$1.50 - \$2.40 / GJ
Carbon Price	\$30/tCO <sub>2</sub> from 2018 to 2020; \$40/tCO <sub>2</sub> in 2021; \$50/tCO <sub>2</sub> from 2022 onwards
Electricity CO <sub>2</sub> Emission Performance Standard	0.370 tCO <sub>2</sub> /MWh in 2018-2019 (declining by 1% per annum starting in 2020)
Coal-to-gas [End of life is based on proposed federal regulations]	Conversion: 2,400 MW (2021-2022) Retirement: 2,400 MW (2035-2037)
New Combined-cycle (2019-2045)	5,544 MW
New Simple-cycle (2019-2045)	1,943 MW
New Wind (2019-2045)	6,200 MW (built in 2019 – 2029) to meet renewable energy target

### Substitution cases

The AESO created a series of substitution cases, whereby wind generation was replaced by dispatchable renewables resources while maintaining a renewable energy target of 30 per cent by 2030. Substitution levels for each dispatchable renewable technology were conducted at 250 MW, 500 MW and 1,000 MW. Although the AESO did not conduct an assessment of potential production capability available in Alberta for each technology, these substitution levels are expected to cover the range of what may be feasible in the province and provide directional incremental impacts at the various capacity levels.

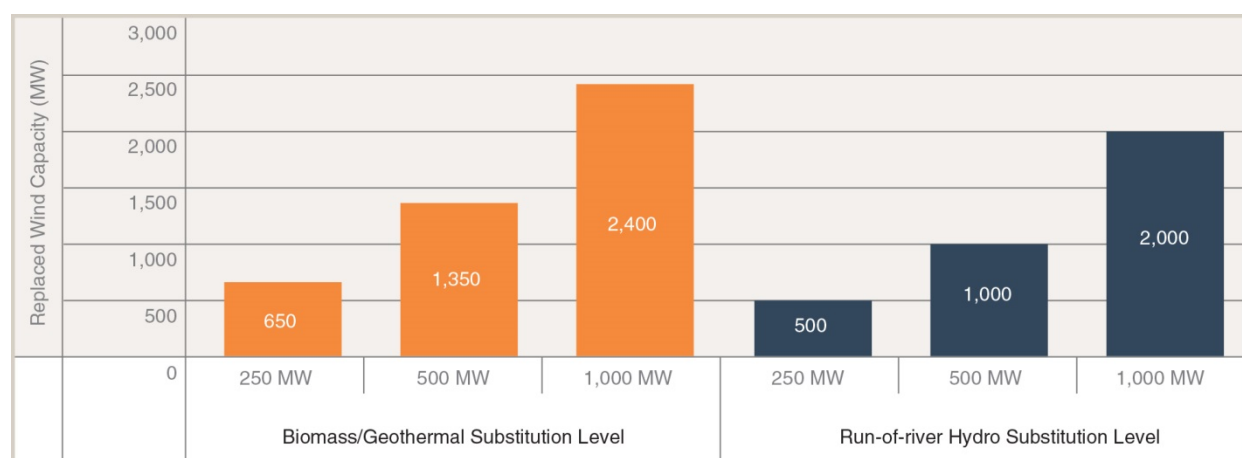


**Figure 3: Dispatchable renewable substitution levels**

	Run-of-river Hydro	Biomass	Geothermal
Substitution Case Inputs	250 MW	250 MW	250 MW
	500 MW	500 MW	500 MW
	1,000 MW	1,000 MW	1,000 MW

Due to differences in capacity factors between wind and other dispatchable renewables, each substitution case resulted in different levels of wind capacity being removed from the 2018–MCTG case. Wind capacity factor was assumed to be 34 per cent based on historical Alberta generation. Capacity factor estimates for dispatchable renewables are based on AESO research and one-on-one discussions with stakeholders. Biomass and geothermal generation are assumed to achieve a capacity factor of 92 per cent. Run-of-river hydro is assumed to have an annual capacity factor of 78 per cent with a daily and monthly shape, which may be representative of a hydro project on a managed river flow system and is materially higher than any existing hydro facility in Alberta today.

**Figure 4: Replaced wind capacity across substitution levels**



The AESO assumed that dispatchable renewable resources will be built between 2021 and 2022. This may not align with procurement, permitting, construction and commissioning timelines unique to each technology and should not be considered as a recommendation to proceed with dispatchable renewables procurement on any timeline. However, this assumption permits assessing the incremental benefits and costs from each substitution case on a comparable basis in time across technologies.

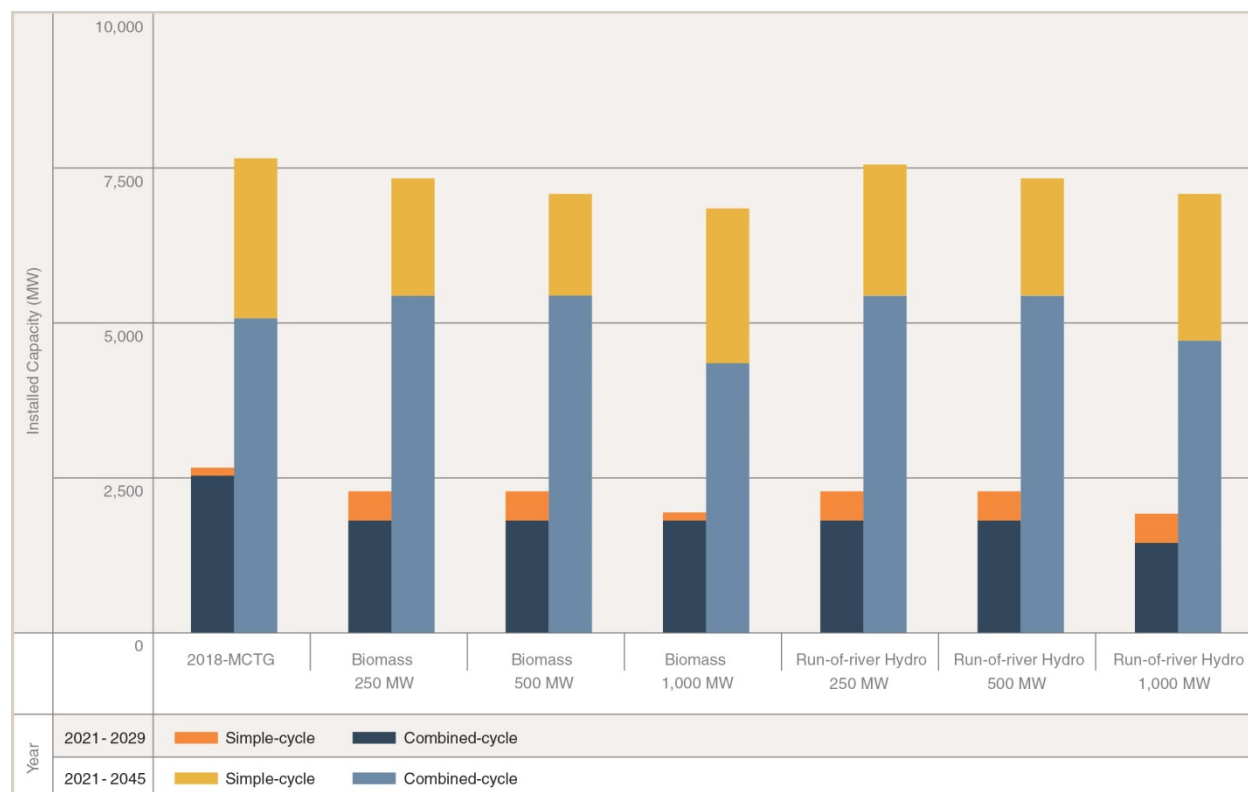
Each substitution case produces a different overall new capacity build profile that adjusts to the attributes that each dispatchable renewable generation type offers in terms of capacity, energy and ancillary services. Simulation results indicate a reduction in gas-based capacity occurs to meet capacity procurement levels, when comparing between the 2018-MCTG and the substitution cases. This highlights the level of firm capacity (reliable capacity that could be counted towards meeting resource adequacy targets) that dispatchable renewables can provide compared to wind. The more dispatchable renewables replace wind, the less gas-based capacity required.

The gas-based supply mix also changes somewhat between simple-cycle and combined-cycle assets when wind is substituted by dispatchable renewables.



Dispatchable renewables are assumed to bid into the market at \$0/MWh, similar to wind, and as a result operate as baseload generation (must-run with a predictable profile). In the 2021–2029 period, substitution case results indicate a reduction in combined-cycle units being built (which primarily provide baseload) and an increase in simple-cycle units being built (which can provide load following and peaking generation more effectively) for different levels of penetration and generation of dispatchable renewables. From 2030 onwards, significant baseload capacity retires from the market (coal assets in late 2020s and coal-to-gas resources in mid-to-late 2030s) prompting considerable amounts of combined-cycle and, to a lesser extent, simple-cycle to be added to the system.

**Figure 5: Incremental installed capacity for gas-fired resources comparison between 2018–MCTG and substitution levels**



NOTE: Geothermal results not shown; capacity build results under the geothermal substitution cases are similar to biomass

### Levelized cost of electricity (LCOE) assumptions

The LCOE estimate is a measure of the overall cost-competiveness of any generating technology. LCOE represents the per-megawatt hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed capacity factor for each technology.

LCOE comparison across technologies must be exercised with caution. LCOE fails to capture the price or revenue streams various technologies are able to extract from the different markets. For example, wind may have a lower LCOE than biomass, but biomass may capture higher revenues from generating at a constant capacity factor even during higher-priced hours.

The AESO reviewed multiple sources of financial and cost information as well as hosted one-on-one discussions with stakeholders (see Section 3 – Stakeholder Engagement for more details) to cross-validate cost estimates relevant to project economics, particularly within the context of the Alberta market.

The AESO incorporated LCOE variances unique to each technology by using ranges around capital costs. For example:

- Wind costs will range based on differences in forecast reductions in turbine production costs
- Biomass costs will range based on differences in boiler type and configurations required to accommodate either straw-fired, forest residue and/or recycled wood from landfill operations
- Geothermal costs will range based on well-drilling depths
- Run-of-river hydro costs will range based on differences in hydrological conditions and site-specific construction conditions

Non-capital costs may also impact the overall economics of a project. For dispatchable renewables, fuel and operating costs are minimal, except for biomass generation where feedstock transportation can be significant. As most renewable generation projects are capital-intensive and require significant capital costs to build, financing cost and financial life assumptions can have a considerable effect on LCOE estimates.

Financing costs are measured by the after-tax weighted average cost of capital (ATWACC) which proportionally allocates costs related to the debt and equity components for each project.

Different factors impact ATWACC parameters. When the project's generation is contracted for in a long-term agreement with an off-taker that has strong credit, this provides a more secure long-term source of revenue for the proponent which typically enables financing the project at higher debt levels with lower debt rates and corresponding lower equity levels at potentially lower equity return rates. Both are favourable factors that lower overall ATWACC financing costs.

Alternately, when the project's generation is sold in the spot market as merchant power, the project's revenues depend on forecasted market prices over the life of the project. Revenues are not as secure as a long-term agreement, resulting in the need for higher equity levels with higher equity returns and lower debt levels with higher debt rates due to the risk of having potentially insufficient revenues. Both are unfavourable factors that increase overall ATWACC financing costs.

Contracted generation, therefore, requires lower financing costs than merchant generation because the off-taker assumes some or all of the revenue risk and removes some or all of the contracted generator's revenue exposure to market volatility. For comparative purposes in this report, the AESO assumes a merchant-based ATWACC at 8.2 per cent and an agreement-backed ATWACC at 4.3 per cent, after adjusting for inflation. Financial life is assumed to be 25 years for all dispatchable renewables. Figure 6 provides LCOE ranges based on different capital costs and ATWACCs for each technology.

**Figure 6: Levelized cost of electricity sensitivity at different capital costs and ATWACC**

	Capital Cost (2017\$/kW)	Levelized Cost of Electricity (2017\$/MWh) 25-year Financial Life	
		Long-term Agreement (4.3%)	Merchant (8.2%)
Wind	1,250	42	55
	1,400	46	60
	1,600	50	66
Run-of-river Hydro	4,000	50	67
	6,500	74	103
	8,000	89	124
Biomass	4,750	115	132
	5,000	117	135
	5,600	122	142
Geothermal	7,677	80	109
	9,801	98	136
	13,842	134	188

*Note: Estimates exclude transmission-related costs*

*Source: AESO calculations based on research and consultation with industry*

The AESO performed an LCOE sensitivity for run-of-river hydro projects to consider varying capital cost estimates for higher construction risks (due to lengthy permitting, geo-technical challenges, longer construction periods) and to consider the longer operational asset life of hydro projects, when compared to other generation resources (including coal and gas). The resulting LCOE estimate ranges are included in Figure 7.

**Figure 7: Run-of-river hydro LCOE (2017\$/MWh) sensitivity at different capital cost, ATWACC and financial life**

Capital Cost Overrun	Capital Cost (2017\$/kW)	Run-of-river Hydro : Levelized Cost of Electricity (2017\$/MWh)			
		25-year Financial Life		50-year Financial Life	
		Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)
1.0x	6,500	74	103	58	92
1.5x	9,750	107	149	82	132
2.0x	13,000	139	195	105	173

*Source: AESO calculations based on research and consultation with industry*

## Future market design assumptions

Currently known design aspects of the Alberta energy, ancillary services and future capacity market are captured in the modelling of this analysis. Specifically, the AESO made simplifying assumptions about changes to energy and ancillary services markets and the implementation of the capacity market based on design features that are part of the Comprehensive Market Design (CMD). While elements of the CMD remain subject to revision and regulatory approval, and the assumptions used for the substitution analysis may differ from final market design, the modelling undertaken and assumptions made are reasonable to provide the indicative cost comparisons across substitution cases.

Key market design assumptions include:

- Energy market – self-commitment with a single bid; large market participants are mitigated to approximately 3x variable costs; wind and dispatchable renewables bid in at \$0/MWh
- Ancillary services market – new entrants participate in active operating reserve markets; maximum operating reserve participation is capped at 80 MW
- Capacity market – capacity is procured to meet acceptable levels of expected unserved energy; dispatchable renewables and wind capacity are not eligible to participate; firm capacity is based on unforced capacity; demand curve is downward-sloping and convex; payments are based on projected missing money of market clearing resource; the reference technology to calculate the cost of new entry is based on a representative simple-cycle power plant

## Incremental Impact Analysis Results

The substitution analysis focused on the incremental changes to three cost categories that capture market costs, emission costs and REP proxy costs. The AESO did not consider potential economic development or other social benefits related to replacing wind with dispatchable renewables.

*Figure 8: Cost categories assessed under the substitution analysis*

	Market Costs	Emission Costs	REP Proxy Costs
<b>What does it include?</b>	Energy, capacity and ancillary services provided by all generators and load	Emissions above a performance standard priced at the ongoing carbon price, as per the <i>Alberta Carbon Competitiveness Incentive Regulation</i>	Akin to the REP, the procurement would include energy, capacity and ancillary services (if any) provided by renewable generators
<b>How is it measured?</b>	Product of prices and amount of energy and capacity procured in the Alberta wholesale market	Product of emissions over the performance standard and carbon price	Product of Indexed Renewable Energy Credit payment (with the strike price assumed to equal LCOE) and the generation exported to the grid
<b>Cost borne by?</b>	Costs are recovered from ratepayers	Costs are paid by generators of emission-emitting resources (resources with emissions below the performance standard receive a credit)	Costs are recovered from the Alberta carbon levy

### Market costs

Market cost impacts can be broken into two components. The first is energy and ancillary services as these markets depend on pool prices and levels of generation provided by the overall supply mix. The second component is the capacity market, which is largely impacted by the amount of firm capacity procured within the capacity market itself, affecting capacity payment prices.

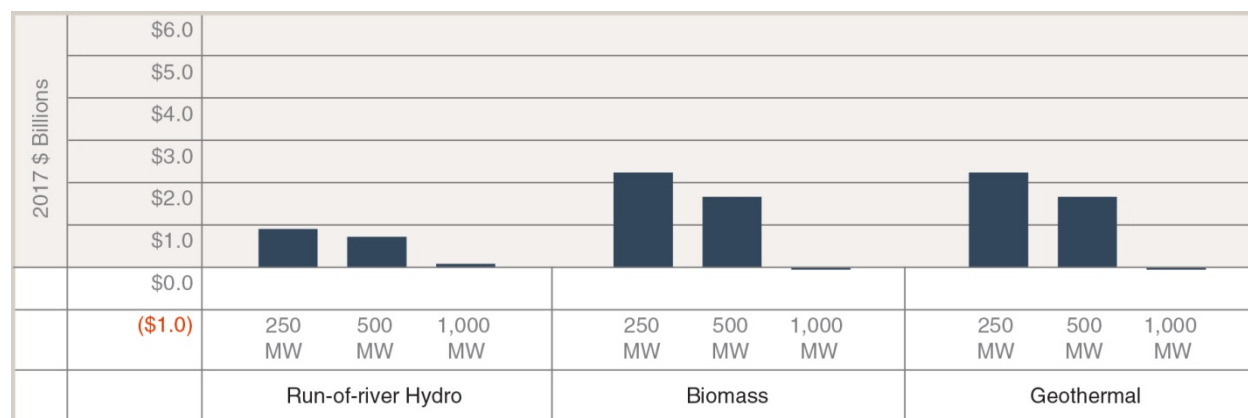
In the energy and ancillary services markets, substitution case results indicate pool prices are higher compared to the 2018–MCTG. Lower wind capacity reduces volatility in prices, particularly the frequency of hours where high amounts of intermittent wind generation lead to significantly lower pool prices. Higher marginal cost resources, such as simple-cycle generators, set marginal prices a higher number of hours. This combined effect translates into higher average pool prices, which indicates that dispatchable renewables (despite offering energy at \$0/MWh) reduces the downward pressure on energy prices produced by wind generation. Higher pool prices translate into higher energy and ancillary services costs for ratepayers; therefore it is considered an incremental market cost.

Substitution cases result in an incremental benefit to capacity market costs. Dispatchable renewables, whose capacity costs are out-of-market and included in the REP proxy costs category, provide greater firm capacity than wind resources. This reduces the overall gas capacity required to meet reserve margin targets, in turn lowering the amount paid to total capacity resources in the market.

Combined, the market costs generally increase (see Figure 9). The increase in energy and ancillary services market costs more than offset reductions in the capacity market. This incremental impact to overall market costs represents an increase between zero and five per cent across the study period, depending on the technology and level of substitution.

This effect is somewhat mitigated as the dispatchable renewables fleet increases to 1,000 MW for two reasons. First, high levels of substitutions reduce capacity market costs to match or exceed increases in energy and ancillary services markets. Second, energy costs decline at 1,000 MW of dispatchable renewables due to energy price reductions from these large volumes, similar to when large volumes of wind enter the market. These two dynamics produce an incremental cost in the energy market that is almost entirely offset by capacity market benefits, resulting in a minimal impact to the overall market cost category.

**Figure 9: Incremental impact to market costs (25-year present value with 8.2% discount rate; 2017 dollars)**



## Emissions costs

Changes to the supply mix due to dispatchable renewables substitutions indicate slightly higher emissions can be expected. Simple-cycle gas generation has lower fuel efficiency and greater emission intensity compared to combined-cycle gas resources. Therefore, a greater presence of simple-cycle generation particularly in the 2021–2029 time period, leads to slight increments to total emissions. This in turn results in an incremental cost to generators, whose payments increase to comply with carbon dioxide emissions regulations. As seen in Figure 10, the incremental change to emissions cost is minimal when compared on the same scale (y-axis) as the other cost categories. This slight increase in emissions costs represents an overall increase between zero and three per cent in emissions compliance costs.

**Figure 10: Incremental impact to emissions costs (25-year present value with 8.2% discount rate; 2017 dollars)**

2017 \$ Billions	\$6.0									
	\$5.0									
	\$4.0									
	\$3.0									
	\$2.0									
	\$1.0									
	\$0.0									
(\$1.0)	250 MW	500 MW	1,000 MW	250 MW	500 MW	1,000 MW	250 MW	500 MW	1,000 MW	
	Run-of-river Hydro			Biomass			Geothermal			

The slightly higher carbon footprint does not affect the overall downward trend in industry emissions. Electricity-sector carbon dioxide emissions are expected to decline as coal-fired generation converts to gas-fired generation to meet proposed federal regulatory standards, or retires by 2030.

### Renewable Electricity Program proxy costs

The AESO assumed, as a proxy for the purpose of this analysis, that the dispatchable renewables will be procured using a similar structure to the REP. This should not be interpreted as a recommendation going forward.

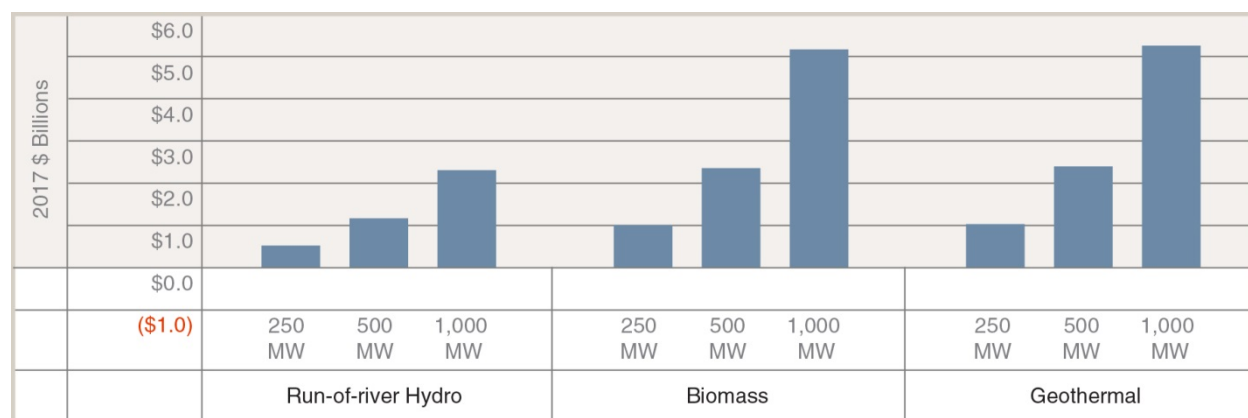
The current REP payment mechanism consists of providing generators an Indexed Renewable Energy Credit (Indexed-REC) in exchange for renewable attributes, energy and capacity. The Indexed REC is calculated by subtracting the pool price from the strike price and the net is paid from (or received into) government revenues.

For modelling purposes, the AESO assumes the strike price of wind resources and dispatchable renewables is their mid-range LCOE with an 8.2 per cent ATWACC from Figure 6.

As wind capacity is reduced and replaced by dispatchable renewables, REP proxy costs will reflect the change in the renewable mix requiring REP payments. Simulation results indicate REP proxy costs will increase across all substitution cases. This is driven by differences in LCOE estimates between wind and dispatchable renewables. Even though dispatchable renewables tend to capture average pool prices and wind receives a discount to pool prices, average pool prices are still below the LCOE of the dispatchable renewables fleet. This increases the need for REP payments, and therefore represents an incremental cost to a REP-type program ranging between a 15 and 140 per cent increase in REP costs, depending on the technology and level of substitution.



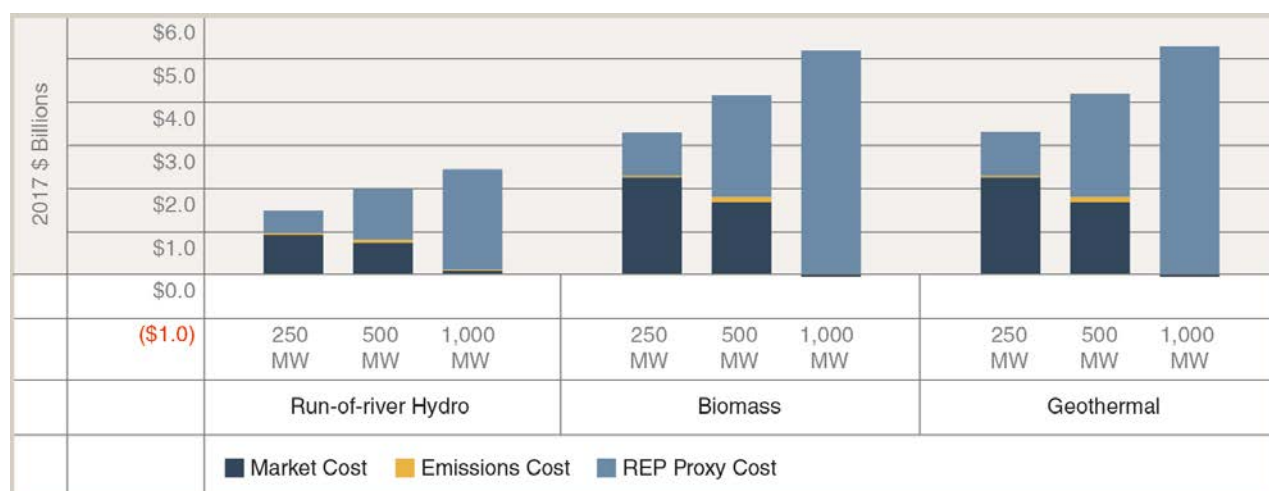
**Figure 11: Incremental impact to REP proxy costs (25-year present value with 8.2% discount rate; 2017 dollars)**



### Combined incremental impact

Even though the three cost categories (market, emissions, REP proxy) used for this analysis are not directly additive because they impact different parties (ratepayers, generators, government revenues), it is illustrative to assess the overall incremental impact of dispatchable renewable substitutions. Taken together, the substitution analysis reveals that, for all dispatchable renewable technologies, there is an overall increase in the combined costs. Simply put, procuring dispatchable renewable energy is forecast to be less cost-effective than intermittent renewable wind energy. Figure 12 provides the incremental total cost impact by substitution level.

**Figure 12: Incremental impact to all cost categories combined (25-year present value with 8.2% discount rate; 2017 dollars)**



### REP proxy cost sensitivity analysis

The AESO performed sensitivity analysis on REP proxy costs by incorporating into the analysis the broad range of LCOE assumptions in Figures 6 and 7, covering different capital cost levels and different ATWACC ranges. Changes in LCOE estimates would drive corresponding changes in total incremental cost as these

sensitivities do not impact market or emission costs. Figure 13 provides the REP proxy costs that result from this sensitivity analysis for the various LCOE assumptions.

**Figure 13: REP proxy cost by LCOE sensitivity across capital costs and ATWACC assumptions (all estimates in 2017\$ Billion, 25-year present value)**

	Capital Cost (2017 \$/kW)	LCOE		REP Proxy Cost by Substitution Level					
				250 MW		500 MW		1,000 MW	
		2017 \$/MWh		PV 2017 \$ B		PV 2017 \$ B		PV 2017 \$ B	
		Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)	Long-term Agreement (4.3%)	Merchant (8.2%)
Biomass	4,750	115	132	0.6	1.0	1.6	2.3	3.7	5.0
	5,000	117	135	0.7	1.0	1.7	2.4	3.8	5.2
	5,600	122	142	0.8	1.2	1.8	2.6	4.2	5.7
Geothermal	7,677	80	109	(0.0)	0.5	0.2	1.4	1.1	3.3
	9,801	98	136	0.3	1.0	1.0	2.4	2.5	5.3
	13,842	134	188	1.0	2.0	2.3	4.4	5.1	9.0
Run-of-river Hydro	4,000	50	67	(0.3)	(0.1)	(0.5)	0.0	(0.9)	0.1
	6,500	74	103	0.1	0.5	0.2	1.2	0.6	2.3
	8,000	89	124	0.3	0.9	0.7	1.9	1.5	3.6
	9,750	107	149	0.6	1.3	1.3	2.7	2.6	5.1
	13,000	139	195	1.1	2.0	2.3	4.1	4.5	8.0

Positive present value estimates mean an increase to REP proxy costs compared to 2018—MCTG, whereas a negative present value (shown in red) estimate represents a decrease to REP proxy costs compared to 2018—MCTG (also see Appendix 5).

LCOE assumptions: 25-year financial life for all technologies; 78% capacity factor for run-of-river hydro; 92% capacity factor and transportation costs (\$44/MWh) for biomass; 92% capacity factor for geothermal.

For biomass and geothermal, under different levelized cost or substitution assumptions, REP proxy costs are positive, indicating an overall REP proxy net cost increase.

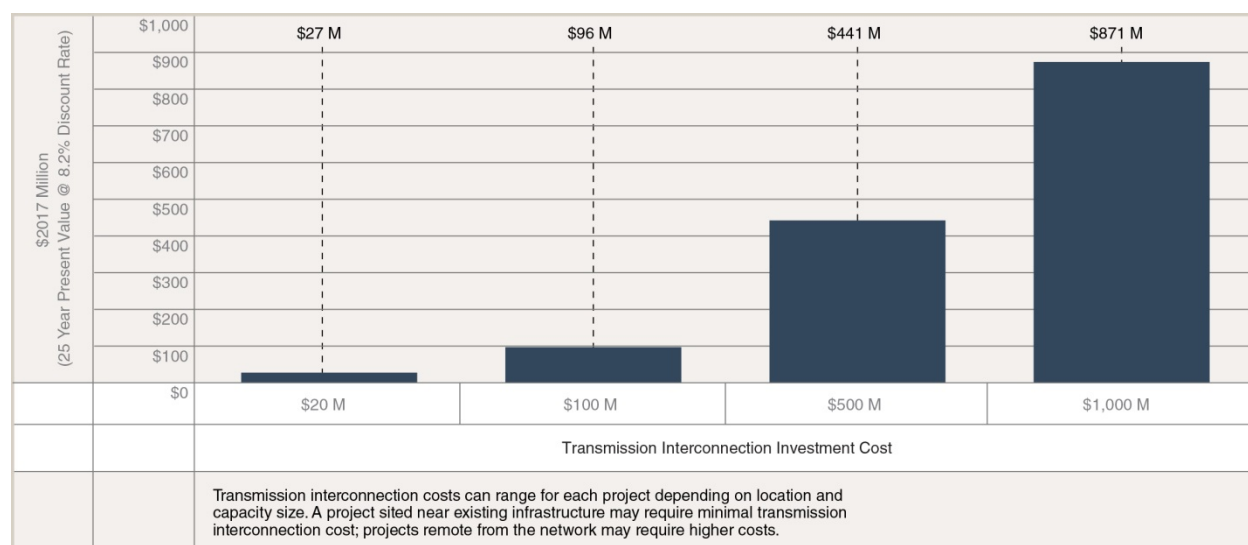
For run-of-river hydro, most capital cost and ATWACC estimates are positive and indicate a net incremental cost. As capital cost and ATWACC move toward the lower end of their respective ranges, incremental REP costs improve and become negative.

For example, for the lowest capital cost range (\$4,000/kW) and lowest ATWACC range (4.3 per cent), REP proxy costs are negative, indicating a potential REP proxy net benefit or reduction when compared to wind. These modelling results are based on a fairly high 78 per cent capacity factor, which reduces LCOE as the costs are spread over more energy. Historically, Alberta’s run-of-river hydro fleet has performed at significantly lower capacity factors. To achieve 78 per cent capacity factor, hydro facilities would need to be located on an already flow-managed system upstream which results in controlled daily and monthly flows without the need to incur the large capital cost of a dam. Building hydro projects on remote locations may also require significant investments in transmission costs, which could offset any potential incremental benefits to REP proxy costs.

### Transmission interconnection costs

Transmission interconnection costs were not directly considered in the comparative analysis, as these costs are very specific to location and capacity size. Instead, the AESO conducted a sensitivity analysis on revenue requirements associated with transmission capital investments to provide directional estimates at different investments levels. These estimates are representative of typical transmission assets and incorporate broad capital investment costs, including depreciation expense, return and interest, income tax, and operations and maintenance expense over a 40-year asset life. Any transmission interconnection costs would be incremental to the total costs in Figure 12.

**Figure 14: Transmission interconnection cost (25-year present value with 8.2% discount rate; 2017 dollars)**



## Summary

The comparative analysis reveals that for all dispatchable renewables technologies, there is an overall increase in total cost. Therefore, procuring dispatchable renewable energy is forecast to be less cost-effective than procuring intermittent renewables wind energy to meet the renewable target. This is primarily as a result of the following factors:

### Market costs increase

- Capacity payments are reduced because less capacity is procured in the capacity market given that the dispatchable renewable capacity is procured through a REP-like program
- Energy costs increase because energy prices increase due to less wind in the market not pulling energy prices as far downward
- As more dispatchable renewable capacity is added, reaching 1,000 MW has a similar effect on pulling energy prices down as does wind, reducing the overall net cost
- These increases are greater than the capacity payment reductions, resulting in a net overall cost increase

### REP proxy costs increase

- The higher levelized cost for various dispatchable renewables as compared to wind drives higher strike prices and therefore higher overall REP proxy costs as energy prices are more often below the higher strike price

### Emissions costs increase

- The marginal increase is due to a slight increase in less efficient gas being built for the baseload dispatchable renewables scenarios versus the wind-based 2018–MCTG scenario, increasing emissions marginally

Depending on remoteness and size of capacity, transmission costs may represent an additional cost that would be added to these three cost categories.

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Appendix 6:  
Energy storage: economic evaluation

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# Economic Evaluation of Energy Storage in Alberta

May 2018



Energy+Environmental Economics

# Economic Evaluation of Energy Storage in Alberta

**May 2018**

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# Executive Summary

## Study Overview

The AESO engaged E3 to assess the potential cost effectiveness of energy storage on the Alberta system. E3 has deep experience modeling energy storage in a wide range of markets including jurisdictions pursuing aggressive renewable development and carbon reduction goals such as California, Hawaii, and New York.

E3 modeled energy storage on the Alberta system using the RESTORE optimization model to calculate the potential energy, operating reserve, and capacity market revenues for the owner of a storage facility. E3 worked closely with AESO staff to model Alberta system conditions and market rules for energy and operating reserves as well as incorporate the design of the future capacity market, utilizing long-term hourly price projections from AESO's own modeling scenarios.

E3 modeled storage dispatch and revenues over a 25-year period, and then compared the discounted present value of those annual revenues to the discounted present value of the capital and operating cost of storage facilities. E3's analysis considered a wide range of storage technologies and potential market price conditions to explore and highlight key insights for the potential impact of storage in the Alberta electric market.

## Key Findings

The key findings of this study are listed below:

**Alberta’s current transmission tariff makes it difficult for storage to be cost-effective in Alberta.** The current tariff charges storage as a load when storage is charging, resulting in relatively high operating costs, particularly for storage used to provide ancillary services. Unless specifically stated, the remainder of this analysis discusses storage assuming no transmission tariff costs are incurred, just the wholesale cost of energy to charge.

**Large-scale storage projects (greater than 50 MW) are unlikely to be cost effective in Alberta, due to:** (1) Early reserve market saturation: AESO’s operating reserve markets provide storage with high revenues per MW, but the market is small; even 50 MW of additional storage into the market may reduce prices (and resulting revenues for storage), and (2) insufficient daily pool price spreads: even with 12 hours of daily “energy arbitrage” (charging 12 hours at low prices and discharging 12 hours at high prices), storage would need more than a \$60/MWh daily price spread to cover a \$2500/kw capital cost. AESO projected daily spreads instead range from \$15-30/MWh.

**Smaller storage projects (below 50 MW) may provide market positive revenues in Alberta from operating reserve and the future capacity market if it is able to:** (1) obtain revisions to the Alberta transmission tariff for charging costs, (2) avoid price saturation in the operating reserve markets that are expected with larger storage additions.

**The trajectory of battery storage prices is declining at an uncertain rate, so before investing in significant storage capacity, it may benefit to wait to observe how quickly batteries’ actual costs fall,** and how quickly the Alberta market’s actual needs for flexibility increase. This deferral may create the opportunity to add storage at a lower cost at a time closer to when it becomes more deeply needed.

These results appear to be robust across a range of future Alberta market conditions reflected in AESO market projection scenarios, including moderate and high levels of coal-to-gas generator conversion; renewable scenarios that target 30% renewable share by 2030; and scenarios that

modeled the AESO system with and without the flexibility to buy and sell energy over its interties to neighboring regions.

**Section 1** of this report provides an overview of the analytical approach and key inputs and assumptions used for this study. **Section 2** highlights the results of the economic analysis. **Section 3** briefly summarizes this study's key findings.

# 1 Analytical Approach

E3 modeled energy storage on the Alberta system using the RESTORE optimization model to calculate the potential energy, operating reserve, and capacity market revenues for the owner of a storage facility. E3 worked closely with AESO staff to model Alberta system conditions and market rules for energy and reserves, utilizing long-term hourly price projections from AESO's own modeling scenarios.

The figure below summarizes the three key components of this study approach.

**Figure 1: Key components of the study approach**



## 1.1 Step 1: Data

The AESO utilized the AURORA production simulation model to represent own scenarios of the future Alberta market. For each scenario developed, the AESO produced hourly pool prices for each year from 2018-2050, as well as annual capacity prices starting in 2021. The AESO also identified hourly price projections for three active operating reserve markets: regulating reserves, spinning reserves, and supplemental reserves. The AESO developed these active reserve prices based on historical data and assumed the prices each year would grow at the rate of inflation.

## 1.2 Step 2: Dispatch

Using the price data provided by AESO, E3 used its RESTORE storage optimization model to calculate the potential revenue from storage participation in Alberta's energy, operating reserve, and capacity markets.

E3's RESTORE model dispatches the storage on an hourly basis to maximize annual revenue to the storage owner, subject to AESO market requirements, and operating constraints of each storage technology. Depending on the scenario, the model allows storage the option in any hour of obtaining revenue from participating in up to five different revenue streams within the three markets:



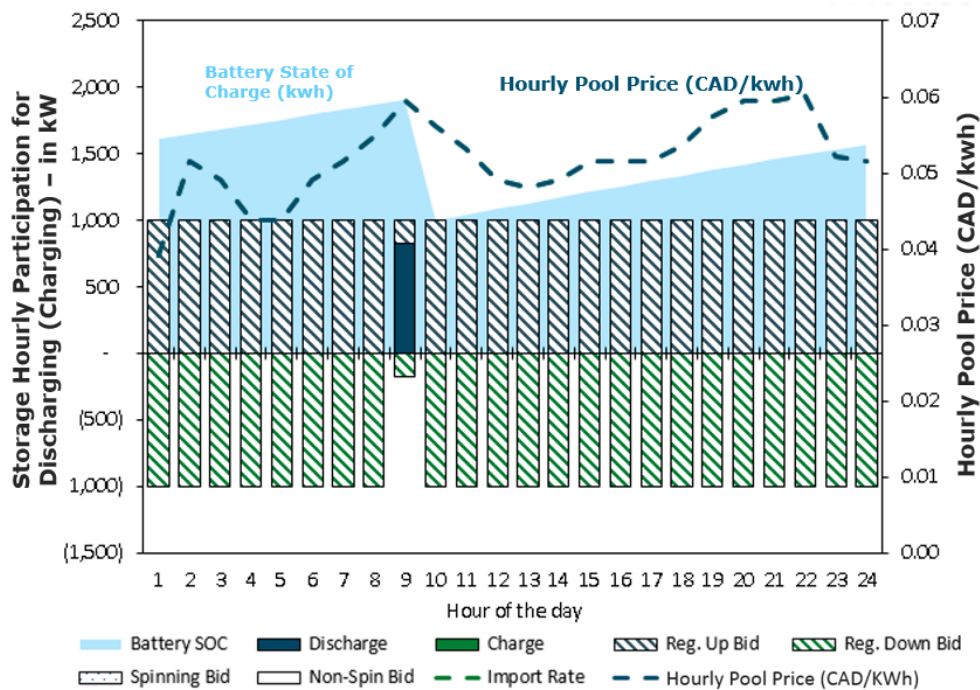
- + **Energy arbitrage**: the model allows storage to purchase energy to charge in hours with low pool prices projected by AESO, and to dispatch the storage to sell energy to the market in hours with high pool prices. The model then calculates the net revenue of energy sales minus energy purchases for charging. The model also accounts for charging, discharging, and standby losses for the storage, slightly reducing the amount of energy available to dispatch in each charge based on specific round-trip efficiency metrics for each storage technology (the total efficiency of charging & discharging storage).
- + **Regulating reserves**: storage reserves upward & downward room on standby and receives dispatch price; a portion of regulating reserves is either utilized, with storage getting directive payment, or the storage charges, incurring storage losses.
- + **Spinning & supplemental reserves**: storage reserves upward room on standby, receives dispatch price.
- + **Capacity**: assumed that storage with 4-hour duration or longer qualifies for annual payment from AESO's planned capacity market. A shorter duration storage facility is assumed to be able to dispatch at rate less than its maximum capacity, qualifying for a reduced capacity payment. For example, a 1 MW 2-hour battery could receive capacity revenues per MW equal to 0.5 MW (=1 MW \* 2 hour / 4 hour). However, longer duration storage still receives the same capacity payment as 4-hour storage.

The RESTORE model's optimization makes dispatch decisions using "perfect foresight" of the prices in each market for each 24-hour period, allowing the model to choose the revenue stream for each hour, or combination of revenue streams, that maximizes the total revenue of storage that day. In actual practice, a storage owner would

need to develop a strategy for bidding and market participation based on uncertain price conditions over the day. Therefore the resulting revenue from the modeled cases function as a benchmark of what the maximum revenue possible would be for a storage unit for a given set of market prices.

The figure below provides an example of RESTORE optimized dispatch for a single day using a 1 MW, 4-hour Lithium Ion (Li-Ion) battery in 2021.

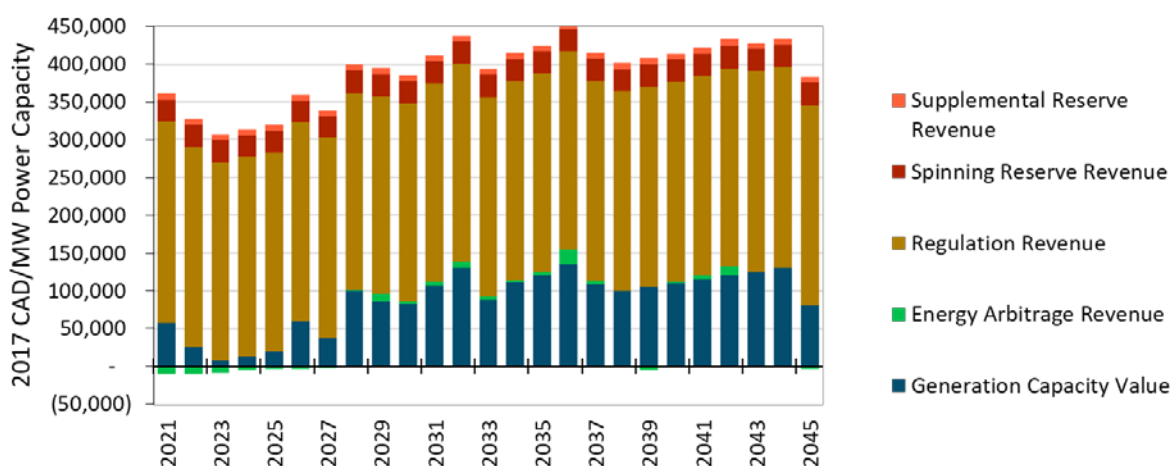
**Figure 2: E3 Storage Model Optimized Dispatch for Example Day**



The RESTORE model accumulates the annual revenues obtained by storage from each revenue stream. The figure below summarizes the optimized revenue for a 1 MW, 4-hour Li-ion battery installed in 2021 in the AESO 2018-MCTG case and operating for a 25-year period. As

described in more detail in the results section, the majority of revenue each year comes from regulating reserves, shown in gold for each year in the chart.

**Figure 3: Annual Revenue for 4-hour Li-ion Battery (2021 Installation in AESO 2018-MCTG Case)**



Note that energy arbitrage revenue in the chart includes the full cost for charging storage in the model and the full revenue from dispatching storage, as well as losses. To the extent that regulating reserves are utilized “or called”, this causes the storage to be directed to charge or discharge in the energy market. The impact of this directed dispatch, and resulting cost of charging and revenue from dispatching, is grouped into the “energy arbitrage” category (green in the chart), along with any energy arbitraging the storage model optimizes in the energy market. The impact of losses from regulating reserve utilization is what leads the energy arbitrage revenues to appear slightly negative in some years.

**Facility size and potential market saturation:** E3 began by modeling each type of storage facility with a 1 MW dispatch capacity (and 1 MW of charging per hour). This approach facilitates comparability of revenues between different storage durations and technologies by assuming each project is of a matching 1 MW size, and battery storage is feasible to purchase at a 1 MW level. In addition, as a price-taker dispatch model, the RESTORE optimization does not endogenously reflect the impact of additional storage to saturate prices. Therefore, it is useful to model 1 MW as a storage addition assumed to be small enough to not impact energy or reserve market prices.

In practice, some potential storage technologies are not feasible to develop at a 1 MW level, but instead require projects sizes on the order of 75 or 500 MW, which would be more likely to impact energy and operating reserve prices if installed on the system. As discussed later in this report, to reflect this impact of “price saturation” from larger projects, E3 modeled separate sensitivity cases that applies a reduction to market prices to reflect the impact of larger projects “price saturating” the energy or reserve markets, and also limits the total amount of larger projects that can participate in a reserve market, as the total AESO operating reserve market is typically 600 MW or less with a small regulating reserve market averaging only 160 MW.

### **1.3 Step 3: Valuation**

Based on the annual simulation results described above, E3 then calculated the present value of annual benefits of storage over a 25-year

period from each revenue source. E3 then compared the total storage revenues to the costs of storage, which include capital cost of the technology, annual operating and maintenance costs, and (depending on scenario) transmission tariff costs. Storage technologies were then identified to have a positive or negative net present value from comparing these costs and benefits.

**Storage cost estimates:** AESO provided capital cost estimates for pumped hydro storage technologies, which were informed by cost estimates from various sources. For battery storage technologies, E3 provided a range of estimated costs for each storage duration and installation year, which were informed by E3's review of various storage technology cost projections including Lazard's 2017 Cost of Storage review.

**Present value calculation:** For calculating the present value of cost and benefits in this study, AESO provided discount rate assumptions consistent with the dispatchable renewable substitution analysis. The analysis assumed a 55% equity share of financing with a 15.5% cost of equity, a 45% debt share with a 5.6% cost of debt and a 27% federal and provincial tax rate. AESO also uses an average inflation rate of 2%. This results in an 8.2% after tax weighted average cost of capital (WACC), which was applied to discount the revenues and costs for storage that are incurred in future years. All present value results are shown for the installation year of the storage project and represented in 2017 Canadian dollars (CAD). For consistency with other AESO analysis, an exchange rate of 1.36 CAD per USD was used for converting U.S. denominated cost projections throughout this study. Storage resources are assumed to be

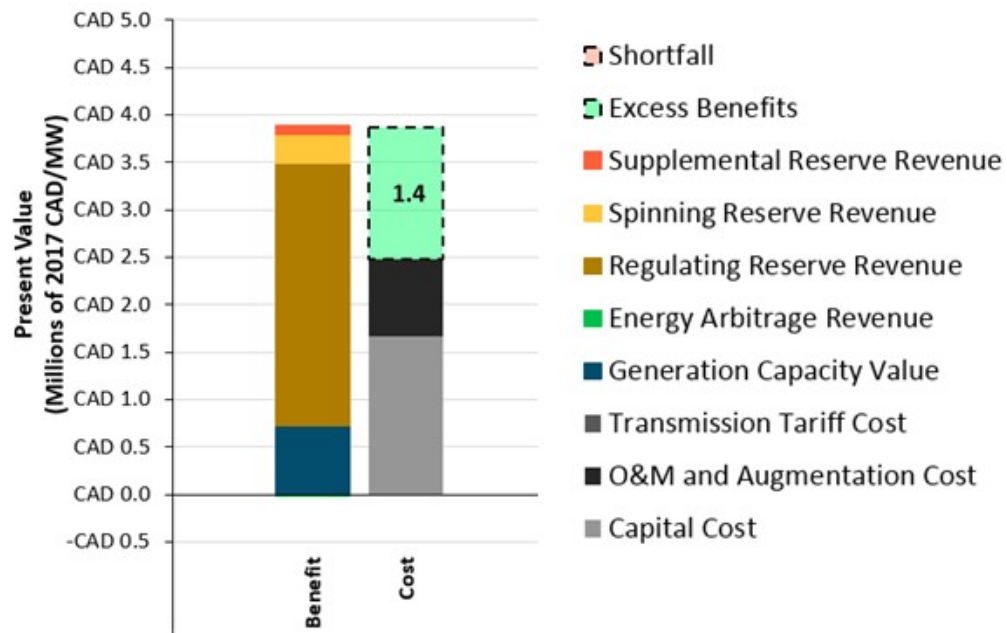
financed over the 25-year operating life at the discount rate provided, which results in a present value exactly equal to the capital cost.

Depending on tax treatment and depreciation schedules, these assumptions may result in conservatively low estimates of total storage costs; actual projected financing may include additional costs such as allowances for funds used during construction, and additional returns for equity owners to cover taxes. The approach, however, allows for a simplified comparative analysis between storage costs and annual revenues. Operating and maintenance costs for storage are provided by E3 data. For battery storage, they include an estimated cost for extended warranty, as well as augmentation of the storage facility to offset degradation of the storage capability. This augmentation is represented as a 3% annual replacement of storage capacity at the prevailing capital costs for the storage at the time. E3 discounted annual operating costs for storage to the installation year using the same 8.2% real discount rate applied for calculating the present value of storage revenues.

**Example of present value results:** The chart below provides an example of the present value results of this analysis, based on a 1 MW capacity, 4-hour duration Li-Ion storage facility with 85% round trip efficiency, installed in 2021 in AESO's moderate level of coal-to-gas conversion (2018-MCTG scenario) for the province. All values in the chart represent present value in 2017 CAD per MW of storage capacity. The left bar of the chart plots the stacked sources of revenue (or benefit) from the storage facility, which here include storage capacity value (blue), regulating reserve revenue (gold), spinning reserve revenue (yellow), and

supplemental reserve revenue (orange). Energy arbitrage value is near zero in this scenario so is not visible in the chart due to the impact of storage losses, and because the storage optimization typically focuses on operating reserve value streams rather than energy arbitrage due to the higher anticipated returns from reserve provision.

**Figure 4: Example of Present Value of Revenues and Costs for a 1 MW, 4-hour Li-ion Battery (2021 Installation in AESO 2018-MCTG Case, 25 Year Present Value with 8.2 % Discount Rate)**



The right column includes the major cost categories for storage, which include capital costs, and operating costs. Transmission tariff costs are not show in this scenario but would also appear in the stacked costs bar. The net present value of each scenario and technology is the difference between the sum of discounted annual revenues (left bar) and the sum of discounted costs (right bar). For this scenario, there is a positive net

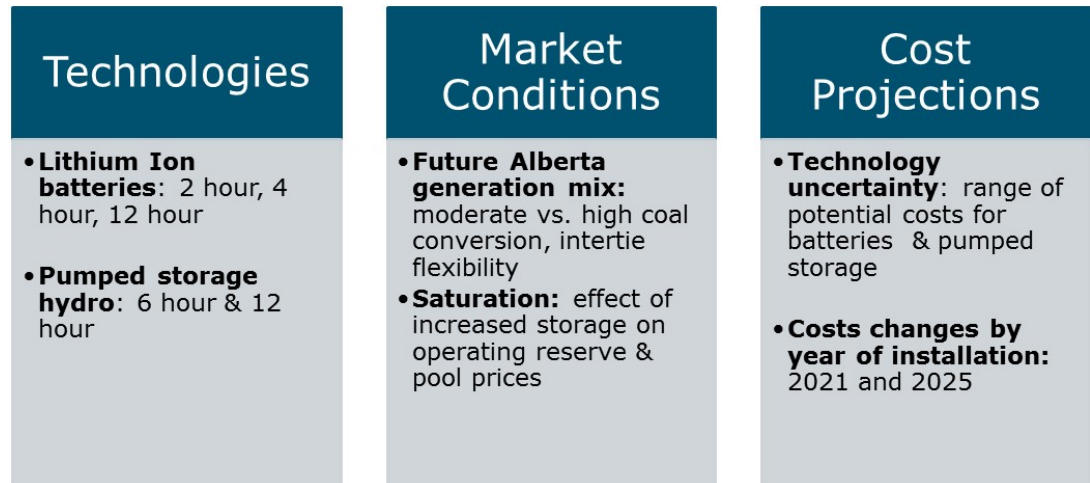


present value for storage, which the chart highlights as the light green area at the top of the right bar, with a value of CAD 1.4 million per MW of storage capacity for this 4-hour duration battery. For scenarios that result in negative net present value, the “shortfall” or difference in revenue versus cost would be shown as a light red area at the top of the left bar of revenues.

## 1.4 Sensitivity Scenarios

E3 utilized the dispatch optimization and valuation approach described above to model the revenues for a wide range of assumptions and scenarios. These sensitivity scenarios allow E3 and the AESO to compare the impact of many factors on storage cost-effectiveness in Alberta, including various technologies, market conditions, and market participation options. The scenarios can also be compared to different technology costs projections.

The table below summarizes key sensitivity conditions considered in this study.

**Figure 5: Key Sensitivity Conditions Considered in this Study**

The key results of the storage study are based on comparison of the present value of storage costs and benefits across these different scenarios. The following section summarizes the major insights from these results.

## 2 Key Study Results

The wide range of scenarios and storage technologies considered produced a large set of resulting costs and benefits for energy storage. This section highlights the key results that provide useful insight about the potential value of storage in the Alberta system. The highlighted results are listed on the following topics:

- + Impact of current transmission tariff on storage
- + Importance of reserve revenue for storage
- + Incremental impact of longer storage duration
- + Sensitivity of storage revenue to saturation of reserve market prices
- + Implications of reserve price saturation for large storage projects
- + Implications of declining battery storage costs
- + Impact of Alberta future resource mix scenarios on storage value
- + Investigation of energy price spreads needed for cost-effective energy arbitrage storage

Many scenarios were evaluated for multiple storage technologies and both a 2021 and 2025 installation year. For conciseness, results in this

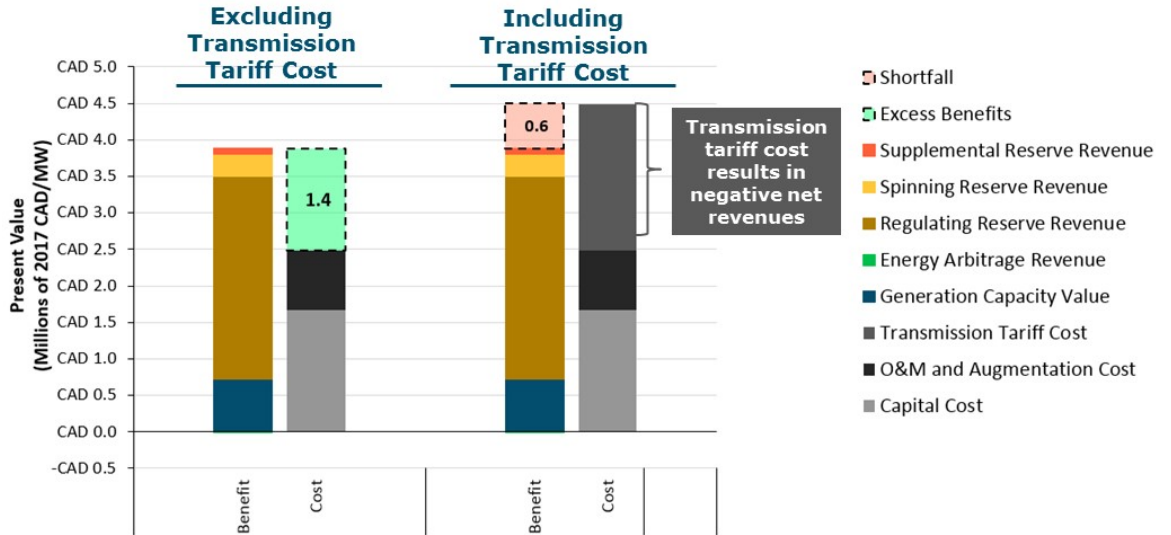
section focus on a 1 MW, 4-hour duration Li-Ion storage unit, unless otherwise noted.

## **2.1 Impact of current transmission tariff on storage**

Under Alberta's currently proposed transmission tariff, storage incurs costs as a load when charging and as a generator when dispatching.

This tariff can impact the cost-effectiveness of storage participating in Alberta's market, particularly for regulating reserves which calls storage to charge and discharge frequently. The figure below compares the present value of revenues and costs for a 1 MW 4-hour battery installed in 2021 with and without the tariff costs applied.

**Figure 6: 2018-MCTG Case Cost-Effectiveness of 4-hour Battery excluding (right) and including (left) Transmission Tariff Cost (2021 Installation, 25 Year Present Value with 8.2 % Discount Rate)**



Without the transmission tariff costs (left side of chart), storage of this size could generate sufficient positive present value of \$1.4 million per MW in the AESO market, largely based on the regulating reserve and capacity market revenues. The transmission tariff costs (shown as dark grey in the right side of chart), however, are projected to total \$2.0 million per MW in costs over the 25-year lifetime of the storage operation, resulting in a net negative present value of -\$0.6 million per MW for the storage facility.

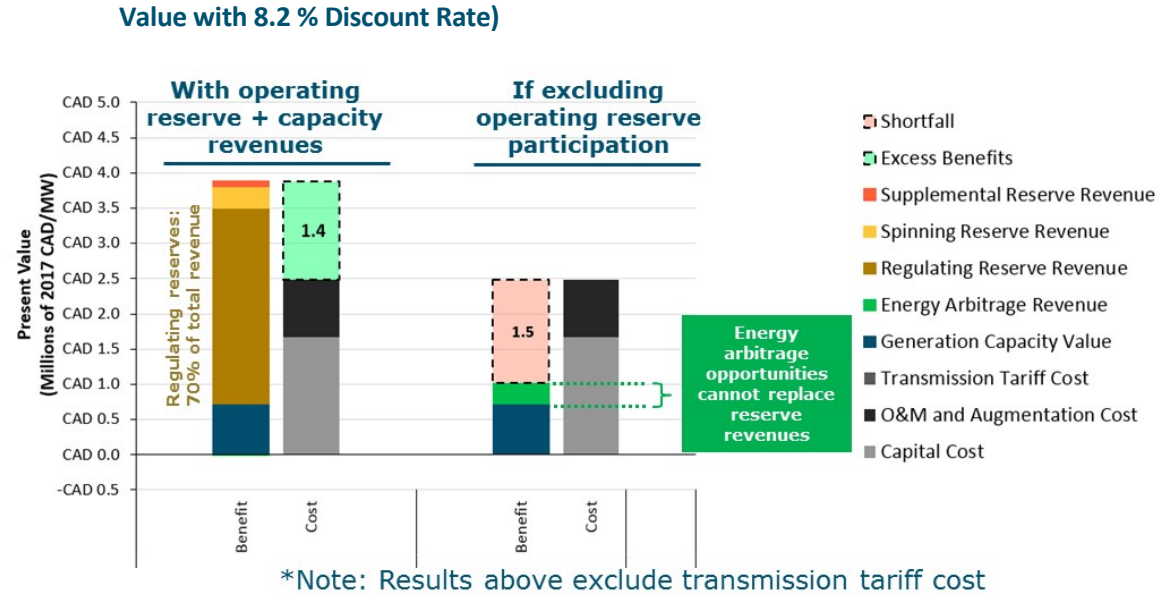
The substantial transmission tariff costs result in negative net present value for all storage technologies and applications evaluated here, even when used primarily for grid support services such as regulating reserve

provision. Due to the consequential impact of tariff costs, AESO directed E3 to focus the remainder of this analysis on comparing storage value while omitting the transmission tariff costs, which could change in the future. Thus, all subsequent results shown in this report exclude tariff costs. To the extent that storage in Alberta would incur transmission tariff costs (under the currently proposed transmission tariff), those costs would need to be deducted from the positive net present value of storage shown below or would be added to the negative net present value storage already identified as not cost-effective.

## 2.2 Importance of reserve revenue for storage

Across all cases modeled, the analysis highlighted the consequential importance of operating reserve revenue for storage cost effectiveness in the Alberta market. The right side of the figure below shows that for a 4-hour battery installed in 2021, regulating reserve provision alone would produce 70% of a total \$3.9 million in present value gross revenue, with the remainder comprised of capacity market value, and other operating reserve value from providing spinning reserve and supplemental reserves in some hours. It should be noted that energy arbitrage is available to the model to select for storage use (left side of chart), but the energy arbitrage revenue in this case is minimal (and too small to be visible in the chart), as discussed below. Thus, reserve revenues are a primary driver of the resulting \$1.4 million per MW in net present value for the facility.

**Figure 7: Base Case Cost-Effectiveness of 4-hour Battery with and without Regulating Reserve Revenue (2021 Installation, 25 Year Present**



By contrast, if opportunities for operating reserve revenues are excluded from the model, the storage unit instead focuses on dispatching exclusively for energy arbitrage (shown on the right side of the chart). This change in focus does result in a present value of \$0.3 million per MW in energy arbitrage revenues, but energy revenues alone are insufficient to replace the excluded reserve revenue, and the reduction in total revenue would instead result in a total net present value of negative \$1.5 million. Note that both cases, which model 4-hour storage, are assumed to qualify for the same annual capacity market revenue. This negative net present value of storage if excluding operating reserve participation is consistent across all cases and technologies modeled, including long-duration storage.

While energy arbitrage is available to the model to select for storage use, energy arbitrage revenue in this case is minimal (and too small to be visible in the chart) for two reasons: (1) for each hour, energy arbitrage and regulating reserve provision are mutually exclusive and represent competing revenue opportunities; the model seeks to maximize revenue for the storage facility and regulating reserves tend to be the higher value revenue option so are selected at most times excluding a limited number of days with particularly high pool price spikes. In addition, (2) the losses associated with discharging and charging storage when regulating reserves are utilized is included in the energy arbitrage category, which may lower the implied revenue by up to \$0.1 million per MW in present value.

There are a few drivers that explain the high value of regulating reserve provision relative to energy arbitrage:

- 1) Regulating reserve prices, which are composed of a dispatch payment that includes an equilibrium price (procured day-ahead) plus the real-time energy pool price, can provide a substantial revenue opportunity for a small storage operator;
- 2) 1 MW of storage can provide up to 2 MW of storage in any hour (1 MW upward when discharging, plus 1 MW downward when charging) provided that the storage unit's state of charge (SOC) retains sufficient energy to provide regulating reserves for up to a full hour of use in the upward or downward direction; and



- 3) Storage can often provide regulating reserves generating positive revenues in nearly every hour of the day, while energy arbitrage for a 4 hour storage facility is often limited to 4 hours of charging and 4 hours of discharging per day unless there are multiple periods of high and low prices in a day.

Absent regulating reserve provision, storage would also be able to provide spinning and supplemental reserves for most hours as well, albeit at lower prices than regulating reserves, operating on standby mode typically and receiving reserve revenue throughout the day. Together, these results highlight the importance of future reserve prices in determining whether storage could be cost effective in Alberta.

### **2.3 Sensitivity of storage revenue to saturation of reserve market prices**

Given the importance of operating reserve market opportunities for determining whether storage is cost effective, it is useful to investigate the stability of reserve market prices. Overall AESO's total operating reserve markets are relatively modest, with typical average daily need of approximately 160 MW of regulating reserves, plus 200 MW of spinning and 200 MW of supplemental reserves. It is important to note that with sufficient duration, 80 MW of energy storage capacity could provide up to 160 MW of regulating reserves under the current AESO rules, based on the sum of 80 MW of upward movement (discharging storage) and 80

MW of downward (charging storage). In the current AESO market, dispatchable hydro generation typically provides more than half of these reserves on average, with coal and gas plants providing the remainder.

Based on historical bid data, the AESO compared active reserve prices in periods with various market liquidity levels. The AESO's analysis indicates that even 50 MW of storage participation in the AESO reserve markets could produce a "saturation effect" that substantially reduces the market prices.

The table below summarizes AESO's estimation of the impact to reserve prices from adding 50 MW of additional low-cost reserves to the market. The table breaks out these results for each operating reserve product and time period (peak vs. off-peak hours). For example, 50 MW of additional regulating reserve participation could reduce prices by 40% during the peak period, and by 88% during the off-peak period. The downward impact on spinning reserve prices is more modest, largely due to the larger size of the spinning reserve market but is still significant.

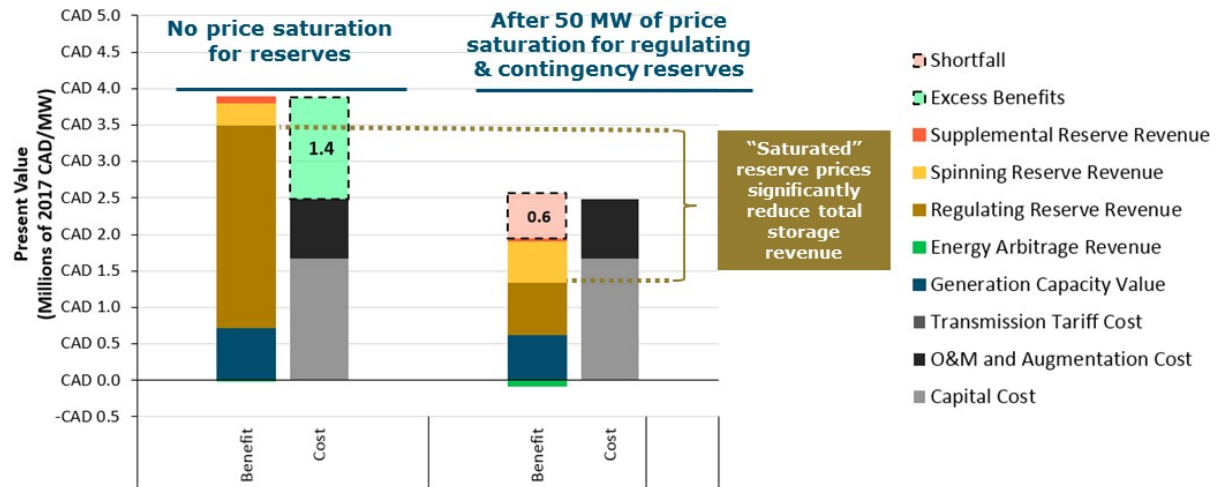
**Table 1: AESO-Estimated Impact on Reserve Prices of 50 MW Market Saturation (During Peak/Off-Peak Hours)**

<b>Regulating:</b>	<b>-40%/-88%</b>
<b>Spinning:</b>	<b>-14%/-32%</b>
<b>Supplemental:</b>	<b>-43%/-52%</b>

Note: 25 MW storage capacity can provide up to 50 MW of regulating reserves in Alberta: 25 MW for charging range + 25 for discharging range

The figure below highlights how much impact the “saturation”-driven price reductions identified by the AESO could have on storage cost-effectiveness. If all 3 revenue streams in the operating reserve market experienced that level of saturation, the net present value of a 1 MW, 4-hour battery installed in 2021 would fall from a positive \$1.4 million per MW before saturation (left side), to -\$0.6 million after price saturation (right side). This change would imply that the market already had received 25 MW of storage allocated to the regulating reserve market, 50 MW to the spinning reserve market, and 50 MW to the supplemental reserve market. A larger share of the revenues shift from regulating reserves to spinning reserves, which is consistent with the smaller reduction in spinning reserve prices compared to regulating reserve prices, but overall revenues are significantly lower.

**Figure 8: 2018-MCTG Case Cost-Effectiveness of 4-hour Battery excluding (left) and including (right) Impact of Saturation (2021 Installation, 25 Year Present Value with 8.2 % Discount Rate)**



These results highlight the importance of considering the magnitude of overall storage deployment in Alberta when projecting the cost-effectiveness of storage in the market. This saturation dynamic is particularly important when evaluating the potential addition of larger storage facilities, which are discussed below.

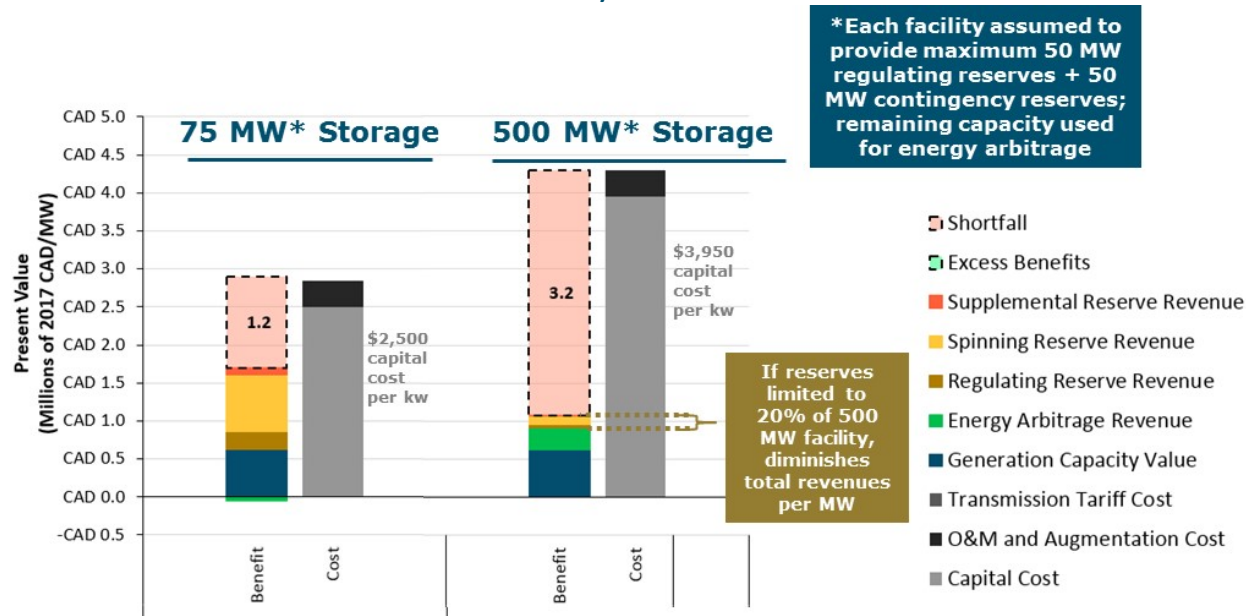
## 2.4 Implications of operating reserve price saturation for large storage projects

Due to the reserve price saturation noted above, achieving cost-effectiveness is likely challenging for larger amounts of storage in Alberta. In addition to the price saturation effect, the modest size of the Alberta operating reserve market will limit the maximum participation from

storage projects. For larger facilities (e.g., storage with greater than 75 MW and more than 4-hour duration), a significant portion of the storage project capacity will need to seek revenues from energy arbitrage. Due to the lower returns from energy arbitrage, such larger facilities would thus receive lower revenue per MW than a small facility that could more exclusively target reserve market revenues.

The figure below summarizes the present value of revenue and cost for two sizes of 12-hour pumped storage hydro facilities. The left side of the chart shows a 75 MW storage facility. The facility is assumed to be able to use 25 MW of its capacity to contribute up to 50 MW of regulating reserves (25 for discharging + 25 for charging), as well as the remaining 50 MW for contingency reserves. The facility can also participate in energy arbitrage when it is more economic than reserve provision. This study again incorporates 50 MW of price saturation into each reserve market – approximately equal to this facility’s own impact on the market.

**Figure 9: Present Value of Revenues and Costs for 12-Hour Pumped Storage Hydro, Assuming 50 MW Price Saturation in Regulating and Contingency Reserve Markets (2021 Installation, 25 Year Present Value with 8.2 % Discount Rate)**



Overall revenues for the project fall to below \$1.8 million per MW, which is lower than the 1 MW battery described above due to the restriction that only a 25 MW portion (33%) of the storage facilities capacity can participate in the more lucrative regulating reserve market, while the remaining portion must seek revenue from contingency reserves or energy arbitrage – which appears in the increasing share of its revenues produced from spinning reserves. The revenues of this facility are compared against a \$2,500 per kW capital cost provided by AESO for pumped storage of this size, as well as the present value of operating and maintenance costs estimated by E3. The net impact of these changes is a

negative net present value of -\$1.2 million per MW, or -\$90 million for the full 75 MW facility.

The right side of the figure models a 500 MW, 12-hour pumped storage hydro facility. The chart applies similar saturation assumptions as that used for the 75 MW unit. The 500 MW unit is assumed to be similarly limited to 25 MW of storage used in the regulating reserve market (providing up to 50 MW of regulating reserves) plus an additional 50 MW contingency reserve provisions. The remaining 425 MW (500 MW total minus 25 MW to regulating reserves minus 50 MW to contingency reserves) is assumed to not be able to provide additional reserves, but instead must seek revenue from energy arbitrage. Like the other storage modeled, the facility is assumed to still be able to capture its full capacity market value per MW. The primary difference in result is that the 500 MW facility can obtain reserve revenues on less than 20% of the unit's total capacity, so regulating and spinning reserve revenues are much smaller per MW. The larger facility does receive some positive energy arbitrage revenue with its remaining capacity, but this is insufficient to substitute for reserve revenue, reducing total revenue to below \$1.3 million per MW. In addition, the larger facility is compared to a \$3,900/kw capital cost provided by AESO, based on estimates for larger pumped storage projects, resulting in a total net present value of -\$3.1 million per MW. For the full 500 MW facility, this would imply a total net present value of -\$1.5 billion.

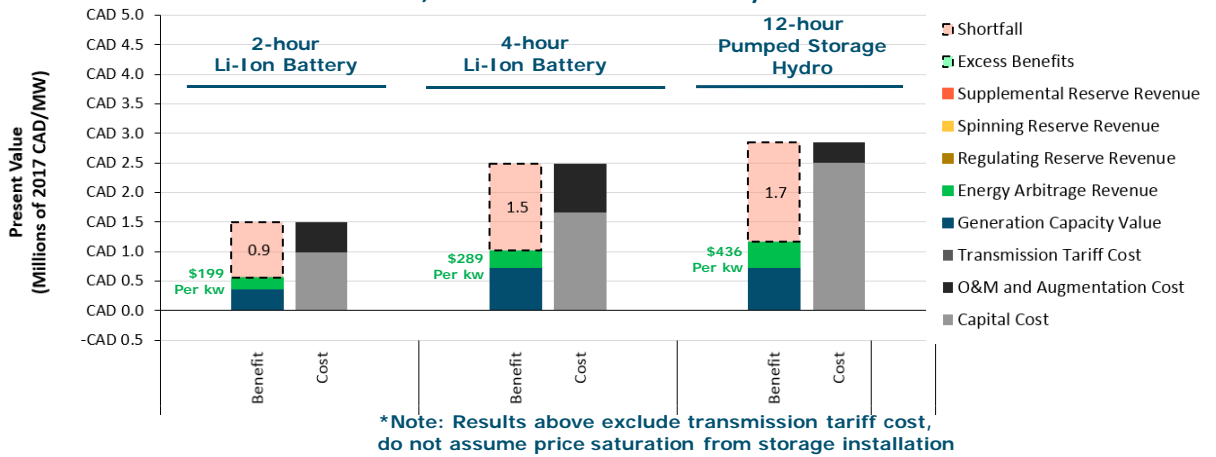
## 2.5 Incremental impact of longer storage duration

Given the sensitivity of reserve revenues to price saturation, it is important to further explore the dynamics that affect potential storage revenue from the energy arbitrage applications – particularly with respect to the impact of storage duration on energy arbitrage opportunities.

The figure below shows the present value of storage, excluding operating reserve revenue opportunities, for a 2021 installation of 1 MW of a 2-hour and 4-hour Li-ion battery, as well as a 12-hour pumped storage hydro facility. These results do not assume a price impact of saturation of storage on pool prices, which would likely have a small downward impact on energy arbitrage revenues for a larger storage facility.



**Figure 10: Present Value of Storage Revenues and Costs for 1 MW Storage of Selected Durations (2021 Installation, 25 Year Present Value with 8.2 % Discount Rate; Excludes Reserve Revenue)**



While all technologies have negative net present value if excluding reserve revenue opportunities, it is useful to compare the energy arbitrage revenue component across the three different storage durations. The 2-hour battery case produces \$199/kw of present value revenue from energy arbitrage. Doubling the battery’s storage duration to 4 hours would create only a 45% increase in the energy arbitrage value to \$289/kw. This implies that the incremental 100% increase in storage duration does not produce a proportionate 100% increase in energy arbitrage value. This result is indicative of the fact that projected AESO energy prices may have 1-2 hours of very high peaks and low values in certain days, but the next 2 hours within each day typically exhibit more moderate price spreads. Thus, while longer duration produces additional value per kw of storage capacity, the increase in energy revenue for the larger duration is at a smaller incremental level than the first 2 hours. Note that the 2-hour battery also has a 50% reduction in capacity value as

it is assumed that 4 hours of dispatch during the system peak is required to obtain capacity revenue. Dispatching at a slower rate of output allows 2-hour storage to obtain half of this revenue.

Similarly, moving upward from 4-hour to 12-hour duration storage (produced by a pumped storage facility) represents a tripling of storage duration, but energy arbitrage revenues increase by only 51% (from \$289/kw to \$436/kw). This further indicates that there is a diminishing energy arbitrage value of incremental storage duration for the price forecasts projected by the AESO. While the increase to 12-hour duration storage would require only a modest increase in storage cost, this cost change is still larger than the increase in energy arbitrage value, as the 4-hour battery storage has a smaller negative net present value than the 12-hour pumped storage facility. As noted previously, longer-duration storage (beyond 4 hours) also has a negligible impact on the ability of storage to provide revenues and, as a result, we conclude that the longer-duration storage does not create positive incremental present value (net of incremental cost) regardless of whether reserve revenues are considered.

## **2.6 Investigation of energy price spreads needed for cost-effective energy arbitrage storage**

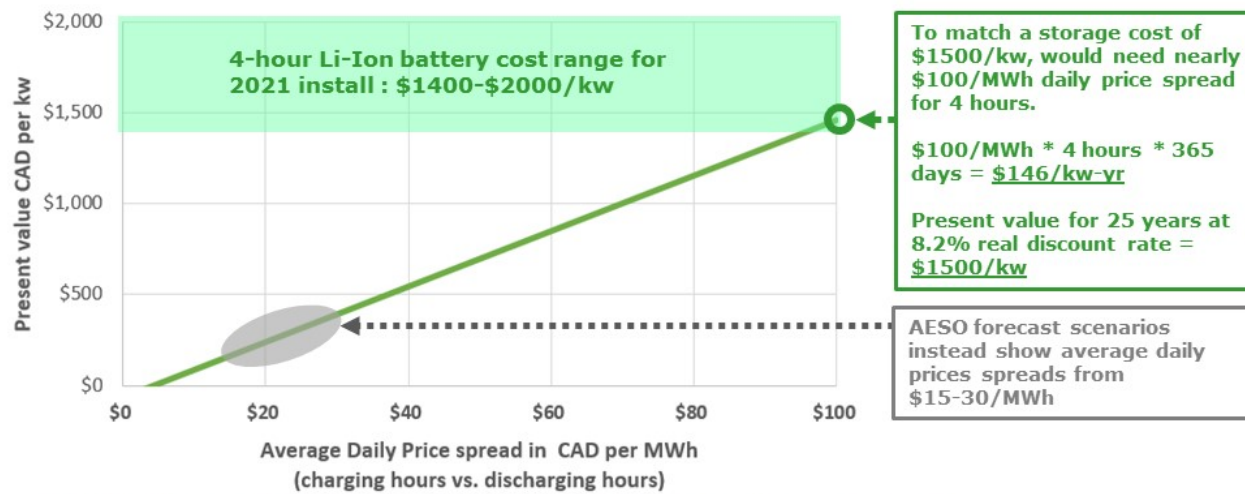
The results shown above with negative value for energy arbitrage are conditional on the pool price shape across each day from the market price projections and resulting spreads between high-price hours and low-price hours, as provided by AESO. In theory, alternative market conditions that

create larger and more regular daily energy price spreads could develop that would lead to sufficient energy arbitrage revenue to cover the cost of longer duration storage. However, with the pending implementation of a capacity market in Alberta, energy price volatility and spreads may decrease when compared to an energy-only market.

Overall, for energy arbitrage plus capacity revenue (that is, excluding reserve revenue) to alone provide positive net revenues that cover the cost of storage, the Alberta market would need significantly wider spreads in hourly energy prices. Moreover, these price spreads would need to occur with regular daily patterns allowing for high utilization of the storage to charge and discharge.

The green diagonal line in the figure below provides a simple reflection of the present-value of energy arbitrage revenues (per kw) for a 4-hour battery (Y-axis), as a function of the average daily price spreads for the 4 hours of discharging vs. the 4-hours of charging (X-axis). The estimates assume that the storage operates with 1 cycle per day (4 hours charging + 4 hours discharging) for 365 days annual for 25 years. Charging and discharging losses are incorporated (assuming 85% round-trip storage efficiency), implying that a battery needs at least a modest positive energy price spread to offset the cost of losses.

**Figure 11: Implied Present Value for a 4-Hour Battery used for Energy Arbitrage as a Function of Average Daily Price Spread**



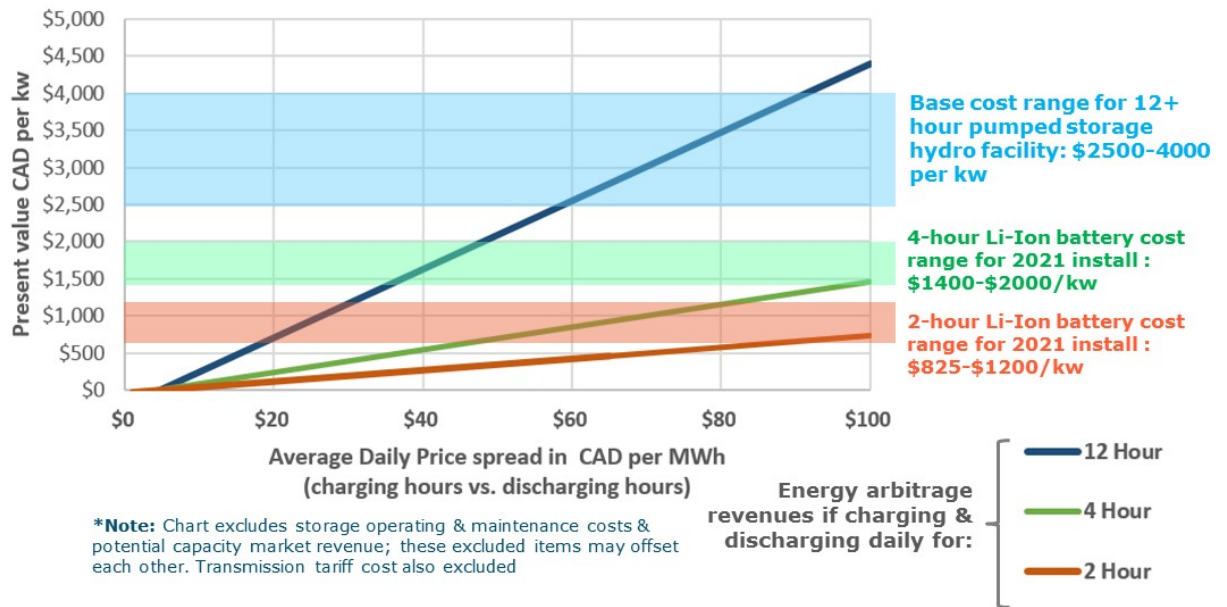
**\*Note:** Chart excludes storage operating & maintenance costs & potential capacity market revenue; these excluded items may offset each other. Transmission tariff cost also excluded. 85% roundtrip efficiency assumed.

The far-right side of the chart highlights that a 4-hour storage battery would need a \$100/MWh price spreads for a 4-hour cycle for 365 days per year to create more than \$1500/kw in revenue from energy arbitrage revenue. This level is near the low range cost estimate for 4-hour battery storage in 2021, which ranges from \$1,400 to \$2,000 per kw. By contrast, the AESO's price forecast exhibits 4-hour spreads of between \$15-30/MWh on average (the grey area in the chart), resulting in an energy arbitrage value still significantly below the cost of storage.

It is important to note that, for simplicity of presentation, this example does not consider the capacity revenue provided by storage, but it also omits the O&M cost of 4-hour storage which has a present value cost that closely offsets the capacity revenue.

The figure below applies this same approach to highlight the duration needed to have positive net present value from energy arbitrage for other storage durations.

**Figure 12: Implied Present Value of 2, 4 and 12-hour Duration Storage used for Energy Arbitrage as a Function of Average Daily Price Spread**



With a shorter duration, a 2-hour duration battery (red line) needs nearly \$100/MWh price spread for energy arbitrage revenue to reach its minimum anticipated installation cost in 2021 of \$825/kw. By contrast, a 12-hour duration pumped storage facility (blue line) would need a nearly \$60/MWh price spread to reach the \$2,500/kw present value in energy arbitrage revenue that would be sufficient to cover the lowest capital cost estimate provided by AESO for pumped storage. Significantly, to generate this revenue level, the pumped storage would need to dispatch to this

\$60/MWh price spread for 12 hours of charging plus 12 hours of discharging (e.g., charge at \$0 for half of the day every day and sell at \$60/MWh for the other half of every day), which is more unlikely to occur versus a 4-hour cycle duration.

## **2.7 Limited impact of Alberta future resource mix scenarios on storage value**

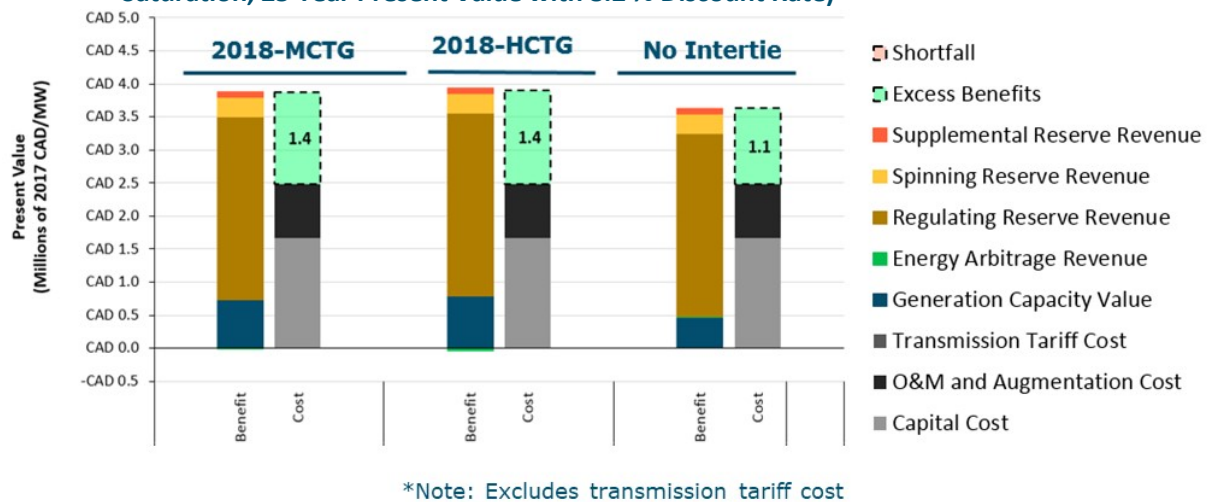
AESO created three scenarios of buildout of the Alberta generation mix, which were then used by E3 to evaluate the impact of each scenario on cost-effectiveness of energy storage. These scenarios include an AESO moderate coal-to-gas conversion (“2018-MCTG”), which includes AESO’s baseline natural gas price forecast, assumes Alberta adds renewables to reach a 30% renewable share by 2030 and then maintains that penetration level for future years, and assumes that Alberta’s interties remain in service to buy and sell energy across the interties based on prevailing expected prices in neighboring markets. The other scenarios include a case with high coal to gas conversion and higher fuel prices for natural gas (“2018-HCTG”), and a “No Intertie” case that removes the flexibility of Alberta to transfer energy between neighboring areas over its interties.

Importantly, the price patterns within each day and across each day vary more significantly between these cases, with the No Intertie case showing the largest daily price spreads (and greatest potential for energy-arbitrage revenue). Despite the overall higher price level of the 2018-HCTG, its daily price spreads remain similar to the 2018-MCTG base case, resulting in

similar energy arbitrage revenues. Significantly, the operating reserve prices provided by AESO were the same across these scenarios.

The figure below summarizes the resulting savings for a 1 MW, 4-hour battery installed in 2021, assuming no saturation of reserve prices. The 2018-MCTG and 2018-HCTG produce very similar net present values due largely to the consistent set of reserve prices across these cases and the importance of reserves in creating storage revenue. The No Intertie case shows revenue that is approximately \$0.2 million per MW lower than the 2018-MCTG due to comparatively lower capacity payments.

**Figure 13: Present Value of Revenue and Costs for 1 MW, 4-Hour Battery, by AESO Resource Scenario (2021 Installation, no Price Saturation, 25 Year Present Value with 8.2 % Discount Rate)**



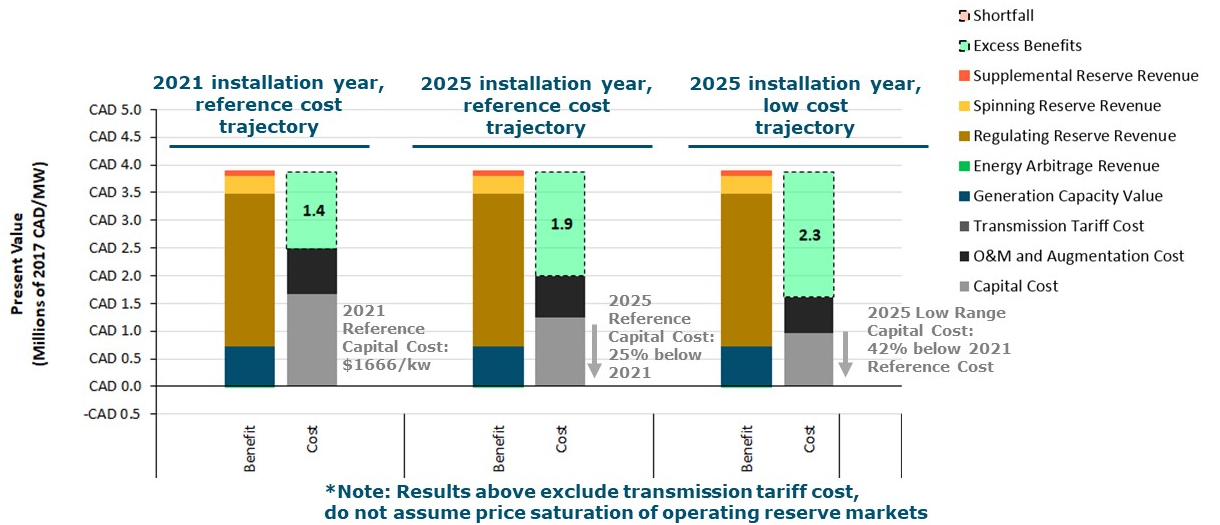
## 2.8 Potential Implications of declining battery storage costs

When considering future market conditions, it is also useful to explore the impact of storage entering the market in 2021 versus at a later period such as 2025, after Alberta renewable penetration has further increased toward the 30% by 2030 target.

The chart below compares the present value cost for a 4-hour 1 MW battery installed in 2021 (left of chart) versus 2025. All present values are discounted to the project installation year but represented in 2017 CAD. The 2025 values are shown with E3's reference case cost trajectory (middle case) and the low range capital cost (right case).



**Figure 14: Present Value of Revenue and Costs for 4-Hour Battery, by Installation Year and Cost Trajectory (25 Year Present Value with 8.2 % Discount Rate)**



For these results, deferring installation until 2025 shows a positive increase in the present value revenues of the project. Reserve prices are assumed unchanged across this period, bringing further consistency across these cases.

Costs for the scenarios, however, change significantly with 2025 reference case capital costs falling 25% below compared the CAD 1,666/kw cost projection for 2021. Battery storage costs have declined rapidly over the last two years, and there is a significant degree of uncertainty over the rate at which they will decline in future years. To highlight this impact, the chart also shows E3's low-range capital cost for 2025 installation on the

right, which is 22% below the 2025 installation reference cost and 42% below the 2021 reference cost. Alternatively, if cost reductions for batteries slow, the 2025 high range capital cost could follow a slower cost reduction trajectory, but this would likely imply that the 2021 capital cost would also be higher than the 2021 reference cost level. Operating cost could also potentially improve over this time period.

Regardless of the storage cost trajectory, the overall downward trend in costs indicates that there may be potential benefits to a later entry into the market for storage additions until system needs for integration increase significantly or until further declines in storage costs occur.

At the same time, a small amount of storage development could create an opportunity for Alberta to modify regulations and operating practices in ways that facilitate further storage development and utilization, which could be beneficial for rapid integration if flexibility needs increase unexpectedly quickly or if storage costs decline particularly rapidly.

### 3 Summary of Key Findings

The primary findings of this study are summarized in the table below.

**Table 2: Key Study Questions and Findings**

+ <u>Key questions</u>	+ <u>Key findings</u>
<p>Would storage be <b>cost effective</b> in the Alberta market?</p>	<ul style="list-style-type: none"> <li>• Alberta’s current transmission tariff makes it difficult for storage to be cost-effective.</li> <li>• If the tariff is revised, Alberta operating reserve &amp; capacity markets may produce revenue to cover the cost of storage additions on a small scale (&lt;50MW)</li> </ul>
<p>How would storage economics in Alberta be affected by <b>saturation</b>?</p>	<ul style="list-style-type: none"> <li>• Alberta projects that 50 MW of storage could significantly reduce operating reserve prices, reducing storage cost-effectiveness of additional storage</li> <li>• Without reserve revenues, “energy arbitrage” revenues alone (from charging &amp; discharging at hourly pool prices) in Alberta unlikely to cover storage costs due to insufficiently large projected daily price spreads</li> </ul>
<p>What <b>uncertainties</b> would most affect projected energy storage cost effectiveness?</p>	<ul style="list-style-type: none"> <li>• The future cost of battery storage is rapidly changing and could affect future cost effectiveness in Alberta over time, especially if transmission tariff can be revised</li> <li>• Alberta’s potential changes in generation mix &amp; system are unlikely to consequentially affect storage cost effectiveness (unless impacting reserve prices)</li> </ul>

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# Appendix 7:

## Regulatory and legal framework review

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# Appendix 7: Regulatory and legal framework review



## Introduction

The following is a summary of the AESO's review of the existing legal and regulatory framework pertaining to dispatchable renewables and energy storage in Alberta. The review was undertaken with a view to identify potential gaps and inconsistencies that may need to be addressed. The review included an examination of applicable rules and legislation, Alberta Utilities Commission ("AUC" or "Commission") guidance, and technical and operational considerations.

## Dispatchable Renewables

The phrase "dispatchable renewables" is not legislatively defined in Alberta. However, the meaning of the phrase may be gleaned from the existing definitions for each discrete term, which are already contemplated in Alberta's legal and regulatory framework. A "dispatchable renewable" is an asset that is both "dispatchable" and "renewable", and these constituent terms are informed by existing rules and legislation.

"Dispatchable" has a commonly understood meaning in Alberta, referring to the ability of an asset to be dispatched. The term "dispatch" is legislatively defined in the *Electric Utilities Act*<sup>1</sup> ("EUA"). A similar definition is incorporated by reference in the AESO Authoritative Documents, including the AESO's *Consolidated Authoritative Document Glossary*<sup>2</sup> ("CADG") and ISO rules pertaining to both the dispatching of assets and pool participants' compliance with dispatches. The definitions of "dispatch" in the EUA and AESO Authoritative Documents each contemplate a direction from the Independent System Operator to a participant "to cause, permit or alter the exchange of electric energy or ancillary services".<sup>3</sup> Accordingly, an asset is "dispatchable" if it is capable of responding to a dispatch in accordance with the ISO rules.

An asset is considered "renewable" if it produces electricity from a "renewable energy resource" as defined in the *Renewable Electricity Act*<sup>4</sup> ("REA"). The REA defines "renewable energy resource" as:

- [...] an energy resource that occurs naturally and that can be replenished or renewed within a human lifespan, including, but not limited to,
- (i) moving water,
  - (ii) wind,
  - (iii) heat from the earth,
  - (iv) sunlight, and
  - (v) sustainable biomass.<sup>5</sup>

In general, all types of renewable assets have an element of being "dispatchable", subject to the ability to respond to ISO dispatches in accordance with the ISO rules. While legislative changes may not necessarily

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<sup>1</sup> SA 2003, c E-5.1

<sup>2</sup> [www.aeso.ca/rules-standards-and-tariff/consolidated-authoritative-document-glossary/](http://www.aeso.ca/rules-standards-and-tariff/consolidated-authoritative-document-glossary/)

<sup>3</sup> EUA, section 1(1)(i); CADG, at "dispatch"

<sup>4</sup> SA 2016, c R-16.5

<sup>5</sup> REA, section 1(l)

be required to incorporate the concept of dispatchable renewables within Alberta's existing regime, there may be a benefit to creating either a new definition, or new term, depending on how these resources will participate in the framework.

## Energy Storage Facilities

### Definition and examination of other jurisdictions

An “energy storage facility” is a facility that:

- converts electric energy by charging;
- stores the converted energy for a period of time; and
- releases the stored energy when it discharges.

This cycle incurs energy losses, meaning that an energy storage facility is a net consumer of energy. By extension, an energy storage facility is not a net producer of energy and would not be considered a dispatchable renewable asset. However, an energy storage facility may bring benefits to an existing renewable asset by storing energy from that renewable asset and discharging the stored energy at a later time.

An energy storage facility may exhibit different attributes depending on its many different uses. For example, it may be used to defer transmission or distribution development, thereby providing attributes similar to a transmission facility or a distribution facility, respectively. Alternatively, the energy storage facility may be used to discharge energy on the Alberta interconnected electric system (“AIES”), thereby providing attributes similar to a conventional generating asset. Conversely, the energy storage facility may be used to withdraw energy from the AIES while charging, thereby providing attributes similar to conventional load.

Authorities in other jurisdictions, including the Federal Energy Regulatory Commission (“FERC”) in the United States and the Ontario Power Authority (“OPA”) and Independent Electricity System Operator (“IESO”) in the province of Ontario, have made efforts to characterize the attributes of energy storage and to provide some parameters for defining energy storage. Prior work conducted within these jurisdictions will provide a helpful starting point for Alberta as it continues to assess the suitability of various definitions for energy storage and related terms.

FERC, for example, had previously defined the term “energy storage asset” as “property that is interconnected to the electrical grid and is designed to receive electrical energy, to store such electrical energy as another energy form, and to convert such energy back to electricity and deliver such electricity for sale, or to use such energy to provide reliability or economic benefits to the grid.”<sup>6</sup> (Footnote in original omitted) FERC has since superseded this definition in Order No. 841,<sup>7</sup> which defines the term “electric storage resource” as “a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.”<sup>8</sup> In Order No. 841, FERC elaborated on its rationale for the definition of “electric storage resource”, clarifying that:

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<sup>6</sup> FERC, *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 144 FERC ¶ 61,056 (2013), Docket Nos. RM11-24-000 and AD10-13-000, at para 172, [www.ferc.gov/whats-new/comm-meet/2013/071813/E-22.pdf](http://www.ferc.gov/whats-new/comm-meet/2013/071813/E-22.pdf)

<sup>7</sup> FERC, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018), Docket No. RM16-23 E-1, Errata Notice (February 28, 2018), <https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14831775> [FERC, Order No. 841]

<sup>8</sup> FERC, Order No. 841, at PDF page 48

[...] this definition is intended to cover electric storage resources capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid, regardless of their storage medium (e.g., batteries, flywheels, compressed air, and pumped-hydro).<sup>9</sup>

[...]

electric storage resources located on the interstate transmission system, on a distribution system, or behind the meter fall under this definition, subject to the additional clarifications provided below.<sup>10</sup>

[...]

by “capable of ... later injection of electric energy back to the grid,” we mean that the electric storage resource is both physically designed and configured to inject electric energy back onto the grid and, as relevant, is contractually permitted to do so (e.g., per the interconnection agreement between an electric storage resource that is interconnected on a distribution system or behind-the-meter with the distribution utility to which it is interconnected). Consequently, the definition of an electric storage resource excludes a resource that is either (1) physically incapable of injecting electric energy back onto the grid due to its design or configuration or (2) contractually barred from injecting electric energy back onto the grid.<sup>11</sup>

[...]

While we decline in this Final Rule to expand the definition of an electric storage resource to include behind-the-meter resources that do not inject electric energy onto the grid, we note that the definition in this Final Rule establishes the minimum set of resources that each RTO/ISO must consider when developing an electric storage resource participation model to comply with this Final Rule. It does not preclude any RTO/ISO from proposing a broader definition for electric storage resources through a separate FPA section 205 filing.<sup>12</sup>

[...]

Some commenters argue that the Commission should broaden its definition of an electric storage resource to apply to behind-the-meter resources that do not inject electricity onto the grid. We decline to do so. Through this Final Rule, we seek to ensure that RTO/ISO market rules account for the unique physical and operational characteristic of electric storage resources, namely their bidirectional capability to both inject energy to the grid and receive energy from it. Expanding the definition of an electric storage resource to include behind-the-meter resources that do not inject electric energy onto the grid would not advance this purpose because they would not be injecting electric energy back to the grid. In addition, we have previously found that behind-the-meter resources that do not inject electric energy onto the grid are considered demand response.<sup>13</sup>

[Emphasis added]

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<sup>9</sup> FERC, Order No. 841, at PDF page 49

<sup>10</sup> FERC, Order No. 841, at PDF page 49

<sup>11</sup> FERC, Order No. 841, at PDF page 51

<sup>12</sup> FERC, Order No. 841, at PDF page 51

<sup>13</sup> FERC, Order No. 841, at PDF page 50

The extracts above highlight the “unique physical and operational characteristic” of electric storage resources and emphasize the importance of an electric storage resource’s ability to not only inject energy to the grid but to also receive energy from it.

In Canada, the province of Ontario has experience with the participation of energy storage within the electricity framework. The IESO’s efforts to describe and characterize the attributes of energy storage include the identification of three broad categories of “energy storage technologies” as follows:

**Type 1** – Energy storage technologies that are capable of withdrawing electrical energy (electricity) from the grid, storing such energy for a period of time and then re-injecting this energy back into the grid (minus reasonable losses). Examples include, but are not limited to, flywheels, batteries, compressed air, and pumped hydroelectric.

**Type 2** – Energy storage technologies that withdraw electricity from the grid and store the energy for a period of time. However, instead of injecting it back into the grid, they use the stored energy to displace electricity consumption (demand) of their host facility at a later time. Examples include, but are not limited to, heat storage or ice production for space heating or cooling.

**Type 3** – Energy storage technologies that only withdraw electricity from the grid like other loads, but convert it into a storable form of energy or fuel that is subsequently used in an industrial, commercial or residential process or to displace a secondary form of energy. They’re generally integrated with a host process that uses that secondary form of energy directly or are connected to a transmission or distribution network for their secondary form of energy (e.g., natural gas, steam or coolant). Examples include, but are not limited to, fuel production (hydrogen or methane), steam production and electric vehicles.

Although all three types can provide services to the electricity system, the differentiation is important in establishing their connection locations and the services they can reasonably provide. For example, a project involving a Type 3 technology located in a heavily loaded area of the system could increase the load on an already constrained local transmission system, potentially restricting it from providing certain services when demand is high (e.g., regulation or flexible supply).<sup>14</sup>

[Emphasis added]

In the context of Ontario’s competitive procurement framework for energy storage, the OPA and IESO also described some of the key attributes of “energy storage systems” as follows:

Energy storage systems have the ability to provide multiple services along the entire value chain of the electrical system. This range of services is based on the fundamental attribute of storage; that is its ability to move energy from one time period to another. In doing so, it can increase the value of the energy produced by other sources and adds capacity value to

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<sup>14</sup> IESO, *IESO Report: Energy Storage* (March 2016), at PDF page 19, [www.ieso.ca/-/media/files/ieso/document-library/energy-storage/ieso-energy-storage-report\\_march-2016.pdf?la=en](http://www.ieso.ca/-/media/files/ieso/document-library/energy-storage/ieso-energy-storage-report_march-2016.pdf?la=en)



the system. It can act as a load and as a generator and provide a range of balancing services both short-term and long-term such as:

- Capacity and congestion management
- Ancillary services
- Allowing for the deferral of transmission and distribution infrastructure investments
- End use customer energy management, including distribution level services<sup>15</sup>

[Emphasis added]

In addition to the preceding descriptions of energy storage, the IESO provided a definition of “energy storage facility” in the context of an IESO-initiated Request for Proposals (“RFP”) process to procure incremental regulation capacity for regulation service.<sup>16</sup>

**“Energy Storage Facility”** means a Facility that uses a commercially available technology that is connected to the IESO-Controlled Grid or a Distribution System and is capable of (a) absorbing grid Energy (charging); (b) storing grid Energy for a period of time; and (c) injecting grid Energy (discharging) back into the IESO-Controlled Grid or a Distribution System, as applicable, or its equivalent (to reduce consumption by approximately the same amount of Energy that was absorbed).<sup>17</sup>

[Emphasis added]

The capabilities of an “Energy Storage Facility”, as described in this definition, are broadly consistent with the three characteristic features of an energy storage facility (charging, storing and discharging) and also appear to align with FERC’s definition of “electric storage resource”. The definition is also notable because it includes facilities that are connected to the distribution system. Further, the definition requires the ability for the Energy Storage Facility to inject energy to the grid, and would therefore exclude Type 2 and Type 3 technologies, as classified by the IESO.

As Alberta considers how it may wish to define energy storage, the experiences in other jurisdictions would suggest there are key aspects that should be contemplated in order to create a suitable definition. Informed by FERC’s and Ontario’s examples, these key aspects include:

- the ability of energy storage facilities to inject energy back into the grid;
- the ability of energy storage facilities to act as both load and generation;
- the time-shifting capability of energy storage facilities;
- allowing sufficient flexibility in the wording and scope of the definition to accommodate future changes to energy storage technology and changes to the needs of the AIES; and
- avoiding an overly-prescriptive definition, thereby providing future flexibility regarding the use of energy storage and the provision of specific benefits or services.<sup>18</sup>

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<sup>15</sup> IESO and OPA, *Energy Storage Procurement Framework* report prepared for the Minister of Energy (January 31, 2014), at PDF page 5, [www.ieso.ca/-/media/files/ieso/document-library/energy-storage/energy-storage-procurement-framework-report-20140131.pdf?la=en](http://www.ieso.ca/-/media/files/ieso/document-library/energy-storage/energy-storage-procurement-framework-report-20140131.pdf?la=en)

<sup>16</sup> IESO website, *Regulation Service RFP*, at [www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp](http://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp)

<sup>17</sup> IESO, *Appendix-H-Form-of-Contract-September-13-2017* (for the *Service Agreement for the Provision of Regulation Service*), at PDF page 11, accessible at [www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp](http://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/regulation-service-rfp)

<sup>18</sup> An example of a specific benefit or service would be the provision of specific ancillary services, similar to the incremental regulation capacity for regulation service procured in the IESO’s above-mentioned RFP process

## Alberta

The examples above and the AESO's jurisdictional review reveal that Alberta is not alone in its attempts to reconcile energy storage with the existing legal and regulatory framework. In Alberta, the terms "energy storage" and "energy storage facilities" are not legislatively defined. Instead, the EUA defines more conventional concepts, as follows:

**"customer"** means a person purchasing electricity for the person's own use,<sup>19</sup>

[...]

**"distributed generation"** means a generating unit that is interconnected with an electric distribution system;<sup>20</sup>

[...]

**"electric distribution system"** means the plant, works, equipment, systems and services necessary to distribute electricity in a service area, but does not include a generating unit or a transmission facility;<sup>21</sup>

[...]

**"generating unit"** means the component of a power plant that produces, from any source, electric energy and ancillary services [...] <sup>22</sup>

[...]

**"interconnected electric system"** means all transmission facilities and all electric distribution systems in Alberta that are interconnected, but does not include an electric distribution system or a transmission facility within the service area of the City of Medicine Hat or a subsidiary of the City, unless the City passes a bylaw that is approved by the Lieutenant Governor in Council under section 138;<sup>23</sup>

[...]

**"transmission facility"** means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less [...] but does not include a generating unit or an electric distribution system;<sup>24</sup>

[...]

**"transmission system"** means all transmission facilities in Alberta that are part of the interconnected electric system.<sup>25</sup>

[Emphasis added]

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<sup>19</sup> EUA, section 1(1)(h)

<sup>20</sup> EUA, section 1(1)(j)

<sup>21</sup> EUA, section 1(1)(m)

<sup>22</sup> EUA, section 1(1)(u)

<sup>23</sup> EUA, section 1(1)(z)

<sup>24</sup> EUA, section 1(1)(bbb)

<sup>25</sup> EUA, section 1(1)(ccc)

As noted in FERC Order No. 841, “electric storage resources” have unique physical and operational characteristics.<sup>26</sup> Energy storage facilities do not easily fit within the existing framework because, depending on their use, energy storage facilities may provide attributes of load, generation, transmission facilities, distribution facilities, or more. However, in the absence of a framework tailored to the unique attributes of energy storage facilities, it is usually necessary to attempt to classify energy storage facilities by referencing conventional categories such as “load” and “generation”, or “distribution” and “transmission”.

Directionally, a definition for energy storage may be better integrated into the existing legal and regulatory framework if it were asset-based (e.g., “energy storage facility”, “energy storage system”, “energy storage asset”, “energy storage resource”, or a synonymous term) and worded as broadly as possible to capture the fullest range of attributes and applications of energy storage, thereby enhancing the flexibility offered by energy storage technology. The AESO supports a definition that focuses on three defining characteristics of an energy storage facility, namely its ability to charge, store, and discharge energy. This approach does not impose restrictions on “where”, “when”, and “how” these functions occur. Further, as discussed above, the use of an energy storage facility would dictate both the appropriate term or descriptor to be applied to the facility, based on the attributes being provided at any given time, and the manner in which the legal and regulatory framework would apply to the facility.

Although the terms “energy storage” and “energy storage facilities” are currently not defined in Alberta legislation, there have been efforts to define energy storage and the approach to this technology in light of the existing regime. The AESO’s CADG defines “energy storage facility” as follows:

**[energy storage facility]** means a facility with technologies capable of storing and releasing electric energy.

To date, a holistic assessment of energy storage in the context of Alberta’s legal and regulatory framework has yet to be performed, and the evolution of how energy storage has begun to participate has occurred on a somewhat reactive and case-by-case basis. For example, the AESO discussed the characteristics of energy storage facilities in a 2015 recommendation paper:

Storage facilities store previously generated electrical energy for release at a later time. Grid scale energy storage technologies include pumped-storage hydropower, compressed air energy storage, power to gas (electrolyzer), battery storage facilities, mechanical flywheels and several others. Each of these technologies converts electric energy into another form of energy for storage (for instance, potential, kinetic or chemical energy), which is then converted back to electric energy at the time it is released.<sup>27</sup>

[Emphasis added]

More recently, the AESO’s 2018 ISO tariff application took a somewhat different approach to energy storage, and appears to exclude an energy storage facility that charges from the electric distribution system:

An energy storage facility has no alternative source of energy other than withdrawing from the transmission system when charging. As well, an energy storage facility cannot forego

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<sup>26</sup> FERC, Order No. 841, at PDF page 50

<sup>27</sup> AESO, *Energy Storage Integration Recommendation Paper* (June 18, 2015), at PDF page 4, [www.aeso.ca/assets/Uploads/Energy-Storage-Integration-Recommendation-Paper.pdf](http://www.aeso.ca/assets/Uploads/Energy-Storage-Integration-Recommendation-Paper.pdf)

withdrawing from the transmission system and still be able to operate as an energy storage facility, thereby becoming unfeasible.<sup>28</sup>

[Emphasis added]

The 2018 ISO Tariff Application also commented on the treatment of energy storage facilities based on their attributes:

In its recommendation paper dated June 18, 2015 [...] the AESO concluded that the current legislative framework supports an energy storage facility being treated as alternating between supplying electricity to the transmission system (similar to a generator) and withdrawing electricity from the transmission system (similar to a load). An energy storage facility would therefore be charged for location-based cost of losses and comparable charges applicable to generators when supplying electricity (discharging) and would be charged for reasonable costs of the transmission system as applicable to load when withdrawing electricity (charging).

Treatment of an energy storage facility as a generator when it is supplying electricity to the transmission system and as a load when it is withdrawing electricity from the transmission system would also be comparable to the treatment of currently existing dual-use sites that include both generation and load.<sup>29</sup>

[...]

Although the legislative framework supports this approach, it does not provide any specific direction that would suggest whether the AESO's existing rates would be appropriate for application to energy storage facilities. The AESO considered that its existing rates may need to be modified or new rates may need to be developed to adequately address the characteristics of energy storage.<sup>30</sup>

[Emphasis added]

The Commission has also provided guidance on energy storage. The Commission issued the *Alberta Smart Grid Inquiry* report ("AUC Smart Grid Report") in January 2011.<sup>31</sup> The AUC Smart Grid Report discussed energy storage but did not define "energy storage" or "energy storage facility". However, the Commission did provide the following description about energy storage:

There are three main types of energy storage: battery storage, compressed air energy storage and pumped hydroelectric storage. The main characteristics of energy storage devices are the energy density (the amount of energy that can be supplied from a storage technology per unit weight) and the discharge time (the period of time over which an energy storage technology releases its stored energy). These technologies can be used for power quality applications as well as for energy management applications or for both purposes.

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<sup>28</sup> AESO, *Alberta Electric System Operator: 2018 ISO Tariff Application* (September 14, 2017), section 8.2 at PDF page 82, para 379, [www.aeso.ca/rules-standards-and-tariff/tariff/current-applications/](http://www.aeso.ca/rules-standards-and-tariff/tariff/current-applications/) [AESO, 2018 ISO Tariff Application]

<sup>29</sup> AESO, 2018 ISO Tariff Application, section 8.2 at PDF pages 79-80, paras 366-367

<sup>30</sup> AESO, 2018 ISO Tariff Application, section 8.2 at PDF page 80, para 368

<sup>31</sup> AUC, *Alberta Smart Grid Inquiry* (January 31, 2011), [www.energy.alberta.ca/AU/electricity/Documents/SmartGrid.pdf](http://www.energy.alberta.ca/AU/electricity/Documents/SmartGrid.pdf)

Recent advances in storage technologies also make them a candidate for providing ancillary services such as spinning reserve, load frequency and voltage regulation, black start operation and other applications.<sup>32</sup>

[Emphasis added, footnote in original omitted]

Further, the Commission discussed whether the existing framework accommodates energy storage facilities as non-regulated generation assets or as regulated transmission or distribution assets:

There would appear to be no barriers to deployment of energy storage facilities as a non-regulated generation asset that could provide energy to the power pool and ancillary services to the AESO. Legislative or policy changes may [however] be required to clarify whether energy storage technologies would be regulated as transmission or distribution assets or be left unregulated and deployed in the competitive generation market.<sup>33</sup>

[Emphasis added, footnote in original omitted]

Collectively, the preceding extracts indicate that Alberta, like other jurisdictions, is dealing with the challenges associated with a consistent definition of energy storage, given that energy storage is a unique technology in the electricity industry. These challenges include defining energy storage and adapting existing regulations, legislation, and market rules to incorporate energy storage. As part of the AESO's Energy Storage Roadmap, the AESO intends to engage stakeholders to help inform a definition for energy storage, and identify potential future regulation, legislation, and market rule changes that would assist in advancing energy storage integration.

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<sup>32</sup> AUC, AUC Smart Grid Report at PDF page 126

<sup>33</sup> AUC, AUC Smart Grid Report at PDF page 19

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# Glossary

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# Glossary

**Activation price:** The price paid to an operating reserve provider if the AESO System Controller dispatches the reserve.

**Active operating reserve(s):** Electricity reserves that meet operating requirements of the Alberta Interconnected Electric System (AIES) under normal operating conditions.

**Ancillary services:** Services necessary to support the transmission of energy from resources to loads based on consumption (for loads) and dispatch (for suppliers).

**Baseload generation:** Generation capacity normally operated to serve load on an around-the-clock basis.

**Behind-the-fence load (BTF):** Industrial load served in whole, or in part, by onsite generation built on the host's site.

**Biomass:** Organic matter that is used to produce synthetic fuels or is burned in its natural state to produce energy. Biomass fuels include wood waste, peat, manure, grain by-products and food processing wastes.

**Capability:** The maximum load that a generating unit, generating station or other electrical apparatus can carry under specified conditions for a given time period without exceeding limits of temperature and stress.

**Capacity:** The amount of electric power delivered or required for a generator, turbine, transformer, transmission circuit, substation or system as rated by the manufacturer.

**Capacity market model:** A market model where generators are paid for having generation available to supply, whether or not any energy is actually produced and supplied.

**Combined-cycle:** A system in which a gas turbine generates electricity and the waste heat is used to create steam to generate additional electricity using a steam turbine.

**Contingency:** An event occurring on the system resulting in the loss of a system element (e.g., outage of a generating unit or transmission line).

**Contingency reserve(s):** A type of reserve used to restore the supply/demand balance when a contingency occurs.

**Curtailment:** A dispatch reduction in variable generation in order to meet a lower demand on the system.

**Demand (electric):** The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time.

**Demand-side management:** Activities that occur on the demand (customer) side of the meter and are implemented by the customer directly or by load-serving entities.

**Dispatch:** A direction from the Independent System Operator to a market participant to cause, permit or alter the exchange of electric energy or ancillary services.

**Dispatchable renewable:** A renewable energy resource that can receive and respond to a dispatch.

**Dynamic stability:** The characteristic of a power system that, when disturbed from an original state through events such as short-circuits, allows recovery to a normal state through damping of the oscillations generated by the disturbance events.

**Emission intensity:** The ratio of a specific emission (such as carbon dioxide) to a measure of energy output. For the electricity sector, emission intensity is usually expressed as emissions per megawatt hour (MWh) of electricity generated.

**Electric storage resource:** A resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.

**Energy Storage Roadmap:** A multi-year plan to progress energy storage integration.

**Energy-only:** A market model where power plants are paid only for the energy they actually produce.

**Federal Energy Regulatory Commission (FERC):** An independent U.S. agency that regulates the interstate transmission of electricity, natural gas and oil. FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines, as well as licensing hydropower projects.

**Frequency excursion:** Any deviation, up or down, of the base frequency of a power system. In North America, the base power system frequency is 60 Hertz (60 cycles per second).

**Generating unit:** Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power.

**Geothermal energy:** Where the prime mover is a turbine driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids beneath the surface of the Earth.

**Greenhouse gas (GHG) emissions:** Gases that trap the heat of the sun in the Earth's atmosphere, producing a greenhouse effect.

**Grid:** A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system.

**Independent system operator (ISO):** A system and market operator that is independent of other market interests. In Alberta, the entity that fulfills this role is the Alberta Electric System Operator.

**Inertia:** The resistance of a physical object to any change in its position and state of motion.

**Interconnection:** An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer.

**Integrated Flexibility Roadmap:** A multi-year plan to regularly assess flexibility requirements and capabilities on the electricity system.

**Intertie:** A transmission facility or facilities, usually transmission lines, which interconnect two adjacent electric systems and allow power to be imported and exported.

**Large Area Control Error (ACE) event:** An event where the area control error changes by more than 65 MW.

**Levelized cost of electricity (LCOE):** The total cost of producing electricity from an asset as a ratio of the total electricity produced by the asset.

**Load (electric):** The amount of electric power used by devices connected to an electric system.

**Long-term adequacy:** The ability of future electric system supply to meet expected electrical demand requirements over several years.

**Losses:** Energy that is lost through the process of transmitting electricity.

**Megawatt (MW):** One million watts.

**Megawatt hour (MWh):** One million watt hours. A megawatt hour measures the amount of electricity produced or consumed in one hour.

**Merit order:** In the wholesale electricity market, the list used to dispatch electric generation to meet demand, based on offer price. The lowest-cost generation is dispatched first.

**Meters:** Equipment that measures and registers the amount and direction of electrical quantities.



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**Net demand:** Load, less variable generation.

**Net demand variability (NDV):** The variability or change in net demand.

**Operating reserve:** Generating capacity that is held in reserve for system operations and can be brought online within a short period of time to respond to a contingency. Operating reserve may be provided by generation that is already online (synchronized) and loaded to less than its maximum output and is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load.

**Peak load/demand:** The maximum power demand (load) registered by a customer or a group of customers or a system in a stated time period. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts.

**Pool price:** The average of 60 one-minute system marginal prices accumulated over an hour.

**Price taker:** A generator that bids into the electricity market at \$0 and receives the hourly market price.

**Ramping:** An increase or decrease in generation output over time.

**Regulating reserve(s):** A type of reserve responsive to automatic generation control that is sufficient to provide normal regulating margin.

**Reliability:** The combined adequacy and security of an electric system. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system facilities.

**Reliability performance metrics:** A set of tests against which the operation of a power system is measured to ensure acceptable performance.

**Reserve margin:** The percentage of installed capacity exceeding the expected peak demand during a specified period.

**Simple-cycle:** Where a gas turbine is the prime mover in a plant. A gas turbine consisting typically of one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand, driving the turbine that in turn drives the generator.

**Solar (power):** A process that produces electricity by converting solar radiation into electricity or to thermal energy to produce steam to drive a turbine.

**Spinning reserve(s):** The amount of unloaded generation that is synchronized to the grid and ready to serve additional demand.

**Standby operating reserve(s):** A type of reserve used when all active operating reserves have been dispatched.

**Strike price:** The price a generator requires for each MWh of renewable electricity delivered during the term of a contract.

**Supplemental reserve(s):** Generation that is capable of being connected to the AIES and loaded within 10 minutes, or load that can be reduced in 10 minutes.

**Supply surplus:** A state where supply of energy available at \$0 exceeds system demand.

**System marginal price:** The price in dollars per megawatt hour determined for each minute of a specific settlement interval.

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**Tariff (Transmission):** The terms and conditions under which transmission services are provided, including the rates or charges that users must pay.

**Thermal overload:** A condition where the thermal limit of a piece of electrical equipment such as a conductor or transformer is exceeded.

**Transfer capability:** The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability can be expressed in megawatts.

**Transmission:** The transfer of electricity over a group of interconnected lines and associated equipment, between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems.

**Transmission system (electric):** An interconnected group of electric transmission lines and associated equipment for moving or transferring electricity in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

**Voltage:** The difference of electrical potential between two points of an electrical circuit expressed in volts. It is the measurement of the potential for an electric field to cause an electric current in an electrical conductor. Depending on the amount of difference of electrical potential, it is referred to as extra-low voltage, low voltage, high voltage or extra-high voltage.

**Voltage stability:** Operation within acceptable voltage ranges. Normal voltage limits are defined as the operating voltage range on the interconnected system that is acceptable on a sustained basis. Emergency voltage limits are defined as the operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

**Western Electricity Coordinating Council (WECC):** An organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state.

**Wind power management:** The ability to adjust wind power output under fast ramping conditions.

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