# Energy Storage in Alberta and Renewable Energy Generation

*An Alberta Perspective on Energy Storage, Applications, Barriers and Greenhouse Gas Emission Reductions*

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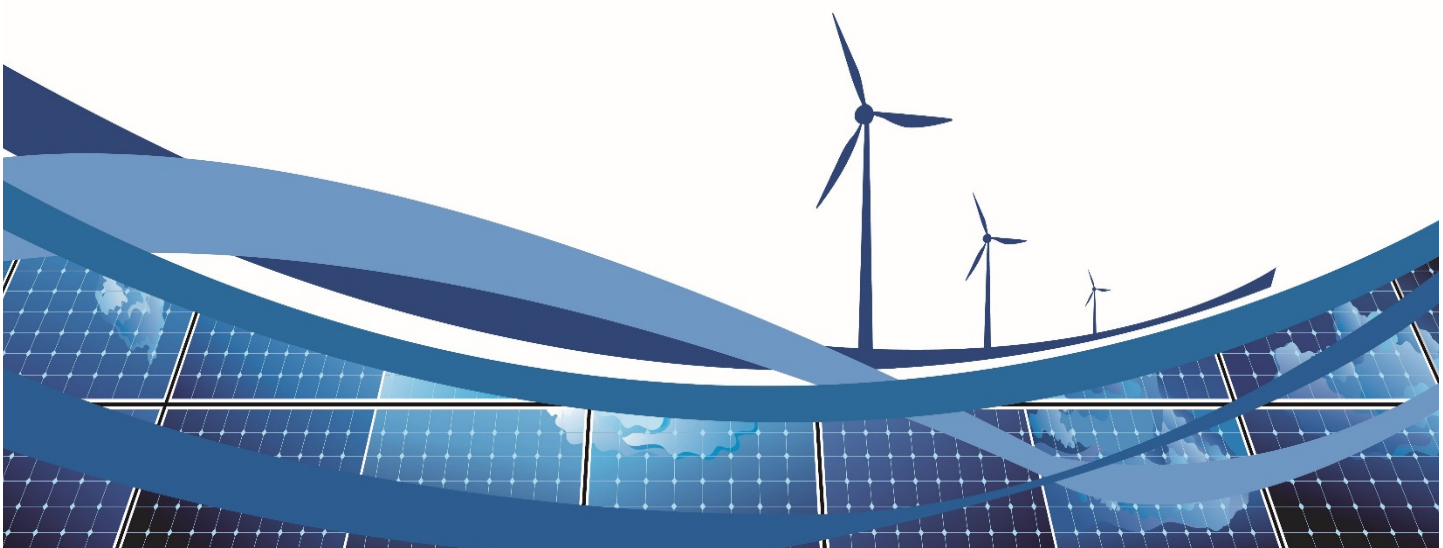

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## Document Purpose

This white paper provides a detailed analysis and basis for understanding energy storage's role in Alberta and its potential implications for the associated greenhouse gases. This paper provides a basis for discussion and contributes to potential protocol development for energy storage.

## Document History

### Energy Storage and Carbon Offsets

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## Disclaimer

## Executive Summary

This report characterises the circumstances where the implementation of energy storage system (ESS) projects reduce greenhouse gas (GHG) emissions. The analysis was completed using current and forecast data for the Alberta Interconnected Electricity System. This report proposes a methodology based on existing globally recognised approaches for quantifying emissions reductions. Also, this report identifies barriers for deploying ESS in Alberta and potential mitigation measures.

ESS is the process of converting electrical energy from a power network into a form that can be stored for converting back to electrical energy when it is needed. Storage can be applied at three key locations in the electricity supply chain: on-site with generation, on-grid with transmission connection, or at the customer site with an electrical load. The role of ESS varies depending on the location of the ESS application. ESS technologies that provide capacity over a short period have fundamentally different applications than technologies that can provide a long duration of sustained energy.

ESS can provide grid flexibility and load support, and today competes with other sources of grid flexibility, such as hydropower, simple cycle gas, curtailment, demand response, to name a few. ESS costs are decreasing at a fast rate, and newer technologies are being developed. ESS market is expected to grow significantly in the next ten years. Technology is advancing appreciably, and costs are decreasing. System operators are now incorporating ESS into planning and operations. Examples include PJM, NYISO, ISO New England, MISO and ERCOT.

Today, Alberta does not use electrical ESS technologies. However, as of November 2016, the Alberta Electric System Operator (AESO) project list of interested developers includes three battery projects for a total of 80 MW and one pumped hydro storage project for 125 MW. Alberta's market is currently an energy-only market and may transition to a capacity and energy market by 2021.[1] The AESO also runs an Ancillary Services market including Operating Reserves, Transmission Must-Run Services, Load Shed Services, and Black Start Services.

In 2014, Alberta contributed over 57 percent towards Canada's electricity emissions. The high coal base in Alberta's generation fleet drives these emissions. Alberta has sufficient renewable energy resources to power all of Canada's electricity requirements on an energy basis. The production profile of renewable energy varies by the type of resource. Variable Generation (VG) is a characteristic of some types of renewable energy that vary seasonally and diurnally such as solar, wind, and to an extent run-of-the-river hydropower. Biomass and large hydropower typically serve as baseload power generation although they may also have variances between summer and winter due to resource availability. Geothermal power generation typically does not vary seasonally or diurnally.

[1] www.alberta.ca/electricity-capacity-market.aspx

The key types of ESS are as follows: chemical, mechanical, electrical energy, and thermal storage. Sandia National Laboratories lists 51 types of ESS technologies within the major categories. ESS differ significantly in their technology, size, capabilities, and capital and operating costs. ESS scalability, power capacity, ESS capacity, cycle life, temperature dependencies, depth of discharge, ramp rates, and response time also differ. Like selecting an automobile, the choice of ESS highly depends on the foreseen usage.

As of May 2016, there are 149 GW of operational storage worldwide with pumped hydro storage representing 97 percent of the total. Chemical ESS using Lithium Ion technology has the largest installation base of electro-chemical based ES. Lead-acid batteries have the highest percentage of decommissioned facilities compared to other electrochemical ESS technologies. The countries with the highest capacity of electrochemical storage installations are USA (33 percent), South Korea (22 percent), Japan (20 percent), and Germany (7 percent). Canada has 1 percent of the installed worldwide capacity of operational electrochemical ESS installations. Most of the electro-chemical and electro-mechanical ESS is deployed in Ontario. Alberta's only storage project listed in the Sandia database is a thermal storage facility at Drake's Landing in Okotoks.

The technical maturity of each ESS technology varies significantly. Pumped hydro ESS and lead-acid batteries are fully mature and have been used for many decades. Developing technologies include fuel cells, metal-air batteries, and isothermal CAES.

Nine Canadian studies pertaining to ESS were reviewed as part of this report, as well as ten US based studies.

Technical, economic, commercial, operational, GHG quantification and regulatory barriers were identified for ESS in Alberta:

a) Technical barriers are technology specific and include examples such as geographic requirements for CAES and pumped hydro, cycle life, high operating temperature for some batteries, experience with design life estimation, run time and round-trip efficiencies.
b) Economic barriers are significant in the current Alberta market design with low prices and low price volatility, and high capital costs. AESO tariff determination for ESS is a significant barrier for ESS economics. Limited revenue opportunities due to the implementation of the operating reserves market.
c) Commercial barriers include lack of long-term contracting capabilities in the current market design and a lack of sufficient experience in operations of ESS in Alberta for lenders to be comfortable. There are few data sources for historical ESS costs for CAES and few installations and little public data on ESS costs.
d) Operational barriers include the size requirements for the operating reserve market which eliminates some technology types. Some have been lowered since the adoption of AESO Rule 502.13 for battery connections and AESO 502.14 for battery operations. Alberta has minimal ESS knowledge skills and training. Dispatch requirements are unclear.

e) Operations and maintenance costs may initially be high; however, will decline with more experience for ESS.
f) GHG Quantification barriers are extensive since there are no protocols that address project specific offsets for ES. Quantification methodology needs to be developed for ESS projects on a stand-alone basis.
g) Policy and regulatory barriers include a legislative gap and a lack of market rules for how ESS participates in energy or operating reserves markets. The new tariff is not attractive for ES. Storage is not currently considered in planning the Alberta transmission system.

Recommendations for barrier reductions are listed below:

- AESO to explore revenue opportunities for ESS that extend beyond energy arbitrage and the current structure of the operating reserves market.
- Improved AESO tariff for ES.
- Clarify AESO ESS dispatch requirements.
- AESO to integrate or consider ESS in the long term outlook
- Develop GHG quantification methodology for ESS projects on a stand-alone basis.
- ES is an emerging technology with potential to provide economic diversity to the province. However, for this potential to be realised, Alberta needs to be positioned as a centre of excellence in ESS which will require the continuation and enhancement of research and development funding and the attraction of external investment.

ES provides multiple benefits to electricity grids, loads, and renewable energy. These include: variable generator capacity firming, variable generator ramping service, VG smoothing, curtailment mitigation, time-shifting/arbitrage, peaking capacity, VAR support, frequency regulation and response (regulating reserves), spinning reserves, non-spinning reserves (supplementary reserves), transmission and distribution asset deferral, peak shaving, uninterruptible power supply, blackstart capabilities and power quality. The value of using ESS for regulating reserve is that this reduces the financial cost associated with the volume of regulating reserves procured. This reduces the overall costs to consumers for electricity.

In 2017, Alberta had eight percent renewable energy (baseload and variable) deployed[2]. An increase in renewable energy deployment is targeted under the Provincial Renewable Energy Program. This deployment will result in a decrease in the overall grid emissions. In Alberta, under the current market regime, most of the issues with renewable energy are due to the economic market and transmission constraints. Renewable energy may encounter the following key issues; policy uncertainty, capture rate wind ghettos[3], significant curtailment at high levels of renewable

[2] Measured on an energy basis.
[3] In today's Alberta wind market, if wind farms are geographically concentrated, they tend to behave as one wind farm and therefore this reduces the power price at times when they are all generating. The result is that all wind farms in that region receive a lower power price. This term is often called a wind ghetto.

energy integration rates, insufficient transmission access, lack of crown land policy, and lagging regulations for renewable energy.

The question as to whether ESS creates emission reductions or enables emission reductions has been debated significantly in Alberta and Canada. There are multiple storage technologies, multiple applications, and three potential locations (at generator, on-grid, at load) for installation of ES. Clearly, the answer is not simple.

An emission reduction is determined by quantifying the difference between the emissions generated in the baseline and the project condition. Current quantification protocols do not specify whether ESS projects integrated on the transmission grid have generated a verifiable emissions reduction. A single, grid-integrated ESS project may provide several services to multiple generators at any time. Thus, a facility of this nature could only generate verifiable emission reductions if the net emissions associated with all provided services result in a measurable reduction.

Solas reviewed quantification protocols for the displacement of grid electricity or ESS and did not identify any quantification protocols or guidance documents related to quantifying emissions associated with ES. Solas developed a framework for quantifying emissions from ESS based on the methodology for the marginal intensity of the electricity grid, quantification protocol guidance provided in the ISO, and Alberta RE protocols. Alberta has seven offset system quantification protocols related to displacing grid electricity with an alternative source. Alberta does not have any protocols that deal directly with ES. The following gaps were identified in the review of existing protocols related to renewable energy generation and quantifying grid emissions: (a) the energy source for charging and ESS location are not considered; (b) the difference between power applications and energy applications for ESS is not included; (c) there is no differentiation between the mix of generation sources making up energy markets and operating reserve markets; (d) time-of-day for charging and discharging and the relevant operating margins is not considered; (e) impacts of congestion on transmission system losses is not considered; (f) impacts on the emissions intensity of partially loaded thermal plants are not included; and (h) specific storage technologies are not identified.

Solas completed analysis on determining the marginal intensity for charging and discharging over 15 different ESS applications in Alberta for seven technologies at three installation locations. The net GHG emissions intensity of ESS was analyzed to determine whether emission reductions were generated by technology, location, and application. Based on the Alberta grid in 2015 and 2030 forecast, results show that ESS generates emission reductions to the extent that it mitigates curtailment of renewable energy generators.

The GHG aspects of ESS differ by technology and application.

- The same technology can have differences in GHG emissions depending on the application this technology.

- The same application can have a wide range of emissions depending on the technology.

In general, isothermal CAES (i-CAES) has the highest emissions intensity when deployed in Alberta in the 2015 timeframe due to the efficiency of this technology. The highest emissions intensity applications include arbitrage, peaking capacity, and peak shaving applications.

The technology with the lowest emissions is flywheels, power batteries, energy batteries and pumped hydro. The lowest emissions for ESS applications are renewable energy curtailment mitigation. The analysis shows that the location of the ESS is not a factor in the emissions profiles. This is discussed in detail in section 9.0.

Emission reductions from ESS are generated when curtailment of renewable energy is avoided. Curtailment can occur from transmission congestion, supply surplus, and ramp rate limitations. Currently, this occurs under localized conditions (e.g., historical Pincher Creek Remedial Action Scheme).

With a thermally based generation mix such as Alberta's current generation, all other ESS applications show an increase in emissions in the Alberta 2015 and an AESO forecasted 2030 grid. The increase in GHG emissions is due to a combination of three factors:

1. ESS facilities are not 100 percent efficient;
2. the electricity that is lost must ultimately come from the grid;
3. the grid in Alberta has a high intensity of GHG emissions.

Having more ESS does allow for a more flexible grid, and therefore allows for more renewable energy integration levels, thereby helping mitigate transmission constraints on increased levels of renewable energy deployment. As seen in places like Maui, where some renewable energy is facing curtailment situations with higher levels of integration, ESS allows for less "spilled wind". At higher levels of renewable energy integration, grid flexibility becomes more important.

ES will become more important in Alberta when: (a) there are issues associated with transmission congestion preventing or "spilling" high levels of renewable energy production, (b) renewable energy production profiles are creating significant extreme ramping events resulting in curtailment, and (c) there are significant supply surplus events that warrant ESS opportunities. ESS will become more prevalent in periods characterised by either higher electricity price volatility, higher energy prices, high delivery charges, or a combination of these environments.

Solas examined the potential for renewable energy curtailment due to multiple factors. These included transmission constraints, ramp rate limits and supply surplus in potential Alberta generation scenarios in 2030 and 2050. The analysis shows some curtailment potential in 2030 at 27 percent wind integration, and much more significant curtailment potential in 2050 when wind integration is assumed to reach 55 percent. The GHG emission reduction potential for ESS in 2050 is estimated at 1.3 MT.

Although the scope of this report was defined to focus on the ability of ESS to directly generate or indirectly enable GHG emission reductions, it is also important to consider the many benefits associated with the deployment of ESS technologies including the potential financial merits of ESS over other methods of improving grid flexibility.

Further study is required to understand the benefit of storage in reducing curtailment at different integration levels and generation mixes in more detail. ESS projects should be supported to develop expertise at the developer, owner and system operator levels. This will create immediate benefits where ESS can be recognised, understood and valued well in advance of the eventual strong demand for ESS that may accompany high levels of renewable energy integration, and transmission and distribution deferral.

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## Glossary

| Abbreviation | Term |
|---|---|
| aa-CAES | Advanced Adiabatic Compressed Air Energy Storage |
| ACE | Area Control Errors |
| AEP | Alberta Environment and Parks |
| AESO | Alberta Electric System Operator |
| AIES | Alberta Integrated Electric System |
| AITF | Alberta Innovates Technology Futures |
| ARS | Alberta Reliability Standards |
| ARS | Alberta Reliability Standards |
| AUC | Alberta Utilities Commission |
| BES | Bulk Electric System |
| BESS | Battery Energy Storage Systems |
| BM | Build Margin |
| CAES | Compressed Air Energy Storage |
| CCEMC | Climate Change Emissions Management Corporation |
| CCGT | Combined Cycle Generation Technology |
| Cogen | Cogeneration Technology |
| d-CAES | Diabatic Compressed Air Energy Storage |
| DOD | Department of Defence |
| DOE | Department of Energy |
| DTS | Demand Transmission Service |
| EGDF | Electricity Grid Displacement Factor |
| EMMO | Energy Market Merit Order |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| ESS | Electrical Storage System |
| FEOC | Fair, efficient, and openly competitive |
| FERC | Federal Energy Regulatory Commission |
| GHG | Greenhouse Gas |
| HECO | Hawaiian Electric Company |
| i-CAES | Isothermal Compressed Air Energy Storage |
| IESO | Independent Electric System Operator |
| ISO | Independent System Operator |
| ISO | International Organization of Standardization |
| LSSi | Load Shed Services for imports |

| Abbreviation | Term |
|---|---|
| LTO | Long Term Outlook |
| MATL | Montana-Alberta Tie Line |
| MSA | Market Surveillance Administrator |
| NERC | North American Electric Reliability Corporation |
| NERC | North American Electric Reliability Council |
| NID | Needs Identification Document |
| NREL | National Renewable Energy Laboratory |
| NSF | National Science Foundation |
| OM | Operating Margin |
| OR | Operating Reserves |
| PJM ISO | Pennsylvania New Jersey Maryland Independent System Operator |
| PPA | Power Purchase Agreement |
| RAS | Remedial Action Scheme |
| RFP | Request for Proposal |
| SATR | Southern Alberta Transmission Reinforcement |
| SCGT | Simple Cycle Generation Technology |
| SGER | Specified Gas Emitters Regulation |
| SMES | Superconducting Magnetic Energy Storage |
| SMP | System Marginal Price |
| SOL | System Operating Limit |
| STS | Supply Transmission Service |
| T&D | Transmission and Distribution |
| TMR | Transmission Must Run |
| UPS | Uninterrupted Power System |
| VG | Variable Generation |
| WECC | Western Electric Coordinating Committee |
| XP | Xtreme Power |

# 1 INTRODUCTION

Alberta has an inexhaustible, world-class, renewable, energy supply that can play a larger role in meeting Albertans' electricity needs. Alberta's solar and wind resources have each been determined to be of similar magnitude to its oil and gas resources in a recent Jacob's study[4] completed for Alberta Energy. Alberta's renewable energy resources have the potential to reduce dependence on fossil fuels and reduce greenhouse gas (GHG) emissions in Alberta's electricity sector.

Alberta plans to green its energy production by achieving up to 30 percent of energy from renewable energy by 2030[5]. In 2015, the Alberta grid had approximately 8 percent of energy from renewable energy. Five percent was from VG sources like wind and solar power[6]. At high levels of integration, the variable nature of some renewable energy, like wind and solar power, can pose a challenge for Alberta's electricity system operator. Expanding Alberta's use of renewable resources may benefit from energy storage systems (ESS) in the future, through reducing transmission build and maintaining system reliability.

ESS is the process of converting electrical energy from a power network into a form that can be stored for converting back to electrical energy when it is needed. Understanding ESS's role in supporting renewable energy integration and associated emission reductions provides a foundation for strategy development and investment decisions in Alberta-based technologies.

Today, Alberta does not use electrical ESS technologies. It has thermal storage at Okotoks, Drakes Landing. In 2015, ESS projects were awarded funding through both Climate change and Emissions Management Corporation (CCEMC) and Alberta Innovates - Energy and Environment Solutions, or were proposed on a merchant basis. As of November 2016, the AESO project list includes three battery energy storage systems (BESS) projects for a total of 80 MW and one pumped hydro storage project for 125 MW. Recognizing the role of ESS technology to enable renewable energy and GHG emission reductions is critical to inform GHG reduction quantification, and potential funding and investment opportunities.

This report characterises the circumstances where ESS reduces GHG emissions or enables renewable energy, which results in reduced GHG emissions. A methodology for quantifying GHG emission reductions is proposed. Also, this report identifies barriers for deploying ESS in Alberta and potential mitigation measures.

This report has the following objectives:

- Provide context for ESS technology and usage.

[4] March 2014, Jacobs Consultancy, Energy Potential and Metrics Study - An Alberta Context,
[5] November 22, 2015 Announcement, Alberta Government, www.alberta.ca/release.cfm?xID=38885E74F7B63-A62D-D1D2-E7BCF6A98D616C09
[6] AESO 2015 Annual Market Statistics Data File

- Identify benefits of ESS for grids, regardless of generation mix, and grids with high renewable energy integration.
- Identify the ESS potential and contribution to GHG emission reductions in Alberta in the near- and long-term.
- Identify barriers to advancing ESS in Alberta — technical, economic, market structure, regulatory, commercial, policy, relevant quantification protocols, etc. — and what might be done to overcome these barriers.
- Characterise how ESS enables the deployment of renewable energy.
- Quantify the potential for emission reductions resulting from ESS.

Solas uses the Alberta Electric System Operator (AESO) 2016 Long Term Outlook (LTO) as a basis for forward-looking estimates of what the Alberta grid may look like. The AESO LTO provides detailed information on how the electricity sector may look. This is only one view of how the electricity sector may unfold.

# 2 ALBERTA'S ELECTRICITY SYSTEM

Electricity is a unique commodity where electricity supply must exactly match consumption always, except when there is storage capability. Alberta's electricity market has 16,302 MW of capacity, plus import capacity. It began operating a wholesale hourly electricity market known as the Power Pool in 1996. January 2001 marked the beginning of the current market structure, which is unique in North America. Alberta's electricity system, by law, requires all wholesale electricity from generation not consumed on site to flow through the Power Pool. This is the physical clearing market. There are few power purchase agreements (PPA) in the market, and PPAs are mostly short-term focused (five years). This lack of long-term PPAs can be a barrier for deploying renewable energy, which typically uses project financing.

Most power is supplied through coal power plants (50 percent of the energy supplied in 2015), as well as gas power facilities. From 2000–2008, the province's demand for power grew at an average of 3.5 percent. This was twice the Canadian and US average growth. The AESO's 2016 estimate of demand growth to 2030 is 2.0 percent. Provincial demand growth, supply additions, and natural gas prices are key influencers over the long-term.

The Alberta Electric System Operator (AESO) operates the Power Pool so that the market is fair, efficient, and openly competitive (FEOC). There are other interrelated markets, including the forward power market, the retail market, operating reserves market, and the dispatch down service market:

- The wholesale power market has a price for electricity in each hour of the year. This market is commonly referred to as a Power Pool. This price fluctuates from hour to hour. All generators submit their offers for the following seven days, with up to seven price-volume pairs. All available capacity must be offered into the pool. This is considered "must offer." Generators can change their offer prices up to two hours prior to the real time. The system operator indicates which facilities it will dispatch based on that hour's demand.
- The forward market allows for the purchase of electricity energy ahead of production and consumption. Forward pricing is available for up to 8 years and relates to the view on how the Power Pool prices settle in the future months. The forward market has little liquidity especially in terms longer than three years.
- The retail market services smaller retail customers and residential consumers.
- The AESO requires operating reserves, including regulating reserves, spinning reserves, and supplemental reserves. The AESO purchases these in the operating reserves market.
- The dispatch down service market allows load to reduce their consumption of electricity and act like negative supply.

The electricity sector can be broken down into three distinct areas: generation, transmission/distribution, and retail. Generation is deregulated; transmission and distribution are almost fully regulated; retail is a mix between regulated and deregulated.

The Alberta Utilities Commission (AUC) approves generation at the facility level. In 2009, Environment Canada indicated that it would regulate coal power facilities starting in 2015 to meet the emissions level of combined cycle natural gas[7]. Facilities that cannot meet the new regulation need to close at the end of their economic life. In Alberta, some of the coal facilities will need to close as early as 2019. Natural gas power, combined with renewable energy, are a natural replacement for legacy coal power.

Alberta's unique electricity features are as follows:

- Currently, Alberta does not pay generators for their capacity availability. This is called an "energy only" market. Many other jurisdictions pay capacity payments and energy payments to generators. Alberta's electricity market requires power pool prices to be sufficiently high to cover operating costs, capital costs, and profit expectations associated with electricity generation.
- Power price has a floor ($0/MWh) and a cap ($999.99/MWh).
- Price bids are fixed two hours ahead of time.
- A few areas of the province have congestion that requires generators to run when they economically would not be running. This contracted service is called Transmission Must Run. Generators with a priority for dispatch due to transmission technical requirements provide this service.
- Alberta pricing is consistent for the entire province and does not take into consideration regional transmission constraints.
- The Alberta market does not have a market nor provides value for generator response times or ramp rates. The AESO equally compensates facilities that are slower to respond and those that have fast response rates based on their energy production only.
- There is no formal day-ahead market that facilitates financial or physically binding transactions.
- The AESO does not facilitate the forward market.

## 2.1 Players and roles

Alberta has a mix of investor-owned and municipally owned companies that supply electricity to Alberta's grid. A mix of investor-owned and municipally owned companies own and operate the transmission and distribution systems.

### 2.1.1 Agencies

The following agencies play a key role in Alberta's electricity market.

The AESO plans and operates the electric system and facilitates the competitive wholesale electricity market. Among its other tasks, the AESO provides open and non-discriminatory access

[7] https://www.ec.gc.ca/lcpe-cepa/eng/regulations/detailReg.cfm?intReg=209

to the grid. The AESO contracts with transmission facility owners to acquire transmission services. The AESO develops and administers ancillary services to ensure system reliability.

The AUC regulates utility companies and approves transmission and generation.

The Market Surveillance Administrator (MSA) site is an independent enforcement agency that oversees the electricity market and ensures the FEOC operation of the wholesale and retail electricity and natural gas markets. The MSA also ensures market participants comply with the Alberta Reliability Standards and the Independent System Operator's (ISO) rules.

### 2.1.2 Generators

There are several dozen companies, mainly investor-owned, that own the electricity generation facilities in Alberta. The generation owners with the most capacity in the province are:

- ATCO Power, owning approximately 1,800 MW of generation capacity (ATCO Power)
- TransAlta Corporation, owning approximately 5,150 MW of generation capacity (TransAlta Corporation)
- Capital Power, owning approximately 2,350 MW of generation capacity (Capital Power Corporation)
- Enmax Energy, owning approximately 1,100 MW of generation capacity (Enmax Energy)

Coal power generators (6,299 MW) in the Alberta market have a minimum level for safe operation, which is typically about 50 percent of their full capacity. Restart costs are economically difficult; therefore, coal plants typically offer as much as 50 percent of their power generation at $0/MWh so that the facility does not become dispatched off. Historically, Alberta's coal power generation fleet has been the province's baseload supply.

Natural gas powered generation (7,227 MW) has expanded significantly in the past 10 years and includes simple cycle (SCGT), combined cycle generation (CCGT), and cogeneration technology (cogen). CCGT also has a minimum generation level for safe operation. Therefore, CCGT offers power at $0/MWh so that the facility does not become dispatched off. Cogeneration is usually tied directly to the heat source. Therefore, their electricity output is must run and is priced into the market at $0/MWh.

Alberta-based hydropower generators (894 MW) have a limited amount of water for the energy-only market, due to water management issues such as flood and drought mitigation[8]. Hydropower is a variable resource for run-of-the-river hydropower generation, or dispatchable for stored hydro facilities. Alberta's hydropower is a combination of dispatchable and VG. The majority of Alberta ancillary services are provided by hydro power.

[8] www.Transalta.com/communities/Canada/alberta-hydro

Historically wind power generation (1,445 MW) was considered in the merit order as a reduction to load, and therefore, was treated as a price taker. This has recently changed where wind power now is shown in the merit order at $0/MWh. Wind power generation is considered a variable resource.

Currently, Alberta's solar power (currently 13 $MW_{DC}$) is distribution connected and not transmission connected. In 2017, the largest installation is two 995$kW_{DC}$ and is, therefore, under the net metering regulations. Solar power generation is considered a variable resource.

Biomass facilities (437 MW) are baseload generation.

Imports and exports are price-takers and are obliged to enter the market at $0/MWh (imports) and $999.99/MWh (exports). Alberta has low import and export capability. In 2015, the average import energy was about 124 MW, and export energy was 76 MW. These values vary by season.

### 2.1.3 Transmission and distribution owners

The main transmission and distribution owners in the province are:

- AltaLink is Alberta's largest transmission owner, operating mainly in southern Alberta.
- ATCO Electric is Alberta's second-largest transmission owner, operating mainly in northern and east-central Alberta.
- Enmax Power owns and operates transmission and distribution lines in the Calgary area.
- EPCOR Distribution & Transmission Inc. owns and operates transmission and distribution lines in the Edmonton area.
- FortisAlberta owns and operates distribution lines in the province.

### 2.1.4 Demand in Alberta

Alberta's electricity demand is often called load, and varies by hour and seasonally. Alberta has a high industrial load (78 percent industrial and commercial, 18 percent residential, and 4 percent farming)[9]. The daily load profile shows an increase in load in the morning and a decrease at night. Seasonally, the winter demand is higher than the summer.

### 2.1.5 Ancillary Services

The *Electric Utilities Act*[10] defines Ancillary Services as those services that are required to ensure the interconnected electric system provides a satisfactory level of service within acceptable levels of voltage and frequency. Ancillary Services includes the Operating Reserves, Transmission Must-Run Services, Load Shed Services, and Black Start Services. The ISO Tariff determines the costs for these services and allocates them to Load.[11] Market participants sell ancillary services to the AESO. In

[9] www.energy.alberta.ca/electricity/682.asp Customer Usage Estimates
[10] www.qp.alberta.ca/documents/Acts/E05P1.pdf
[11] www.aeso.ca/tariff/8777.html

2012[12], the total annual cost of ancillary services was approximately C$363 million. The types of Ancillary Services offered in Alberta are shown in Figure 1.

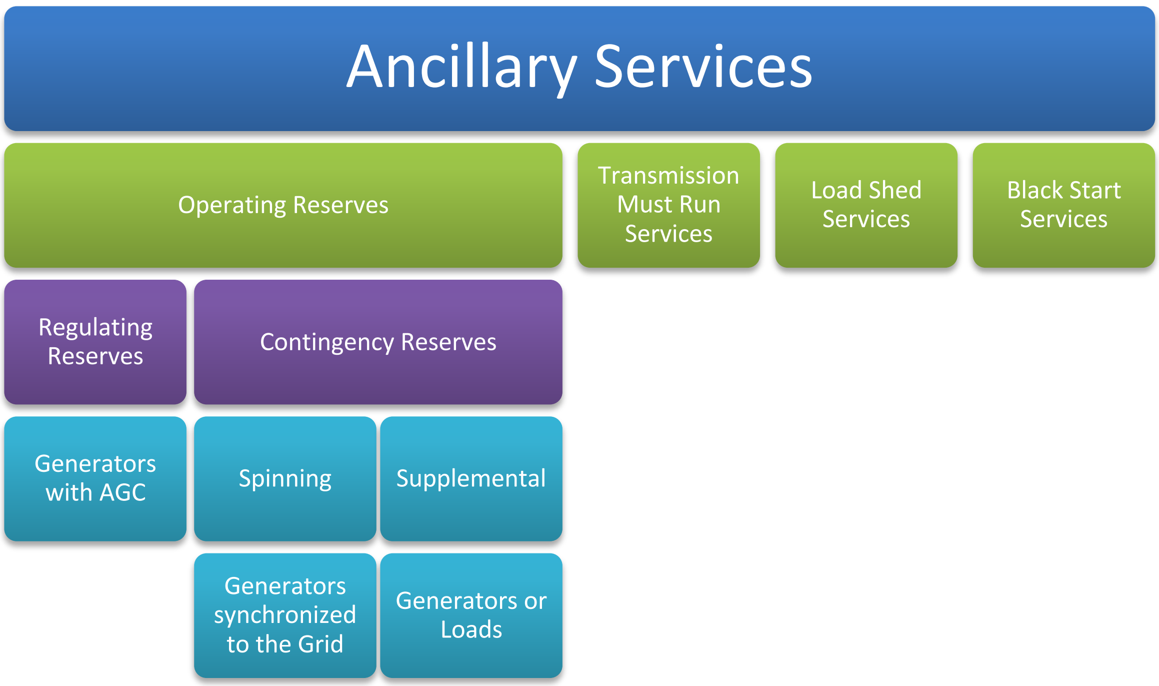


**Figure 1: Types of Ancillary Services — Alberta**

- The AESO contracts Black Start Services through bi-lateral agreements. There is only one provider of this service.
- The AESO uses Load Shed Services to support higher electricity import levels on the Alberta-BC Tie Line. This service has a fixed price availability payment of $5/MWh, and a contract pricing for arming and trip payment of $1,000/MWh.
- The AESO contracts Transmission Must-Run services through bi-lateral agreement with generators. Section 11 of the AESO tariff sets out the payment for conscripted transmission must run.

A third party, Watt-Ex, operates the Operating Reserves (OR) market. The AESO is a market participant in the OR. Unlike the energy market, participation in the market is voluntary. Contracts govern market activity, rather than rules. The OR prices are indexed to the energy market pool price. The energy market participants supply the operating reserves. The annual total cost of the OR Market was $326 million in 2012 and $138 million in 2015[13]. The decrease in OR costs is associated with the decrease in the power pool price. Procurement is done on a day ahead basis.

[12] Operating Reserves Presentation, Biju Gopi, Manager, Commercial Services, September 26, 2013
[13] 2015 Annual Market Statistics Data File, AESO, 2016

OR is purchased using four different time blocks: on peak, off peak, morning super peak, and evening super peak.

There are minimum requirements to qualify for OR market. Regulating Reserves require 15 MW, Spinning Reserves require 10 MW, and Supplemental Reserve require 5 MW. Once qualified, there is an option of selling 5 MW or a greater volume. Each service requires the provider to deliver this service for a minimum of one hour. Table 1 provides the technical requirements for the OR market in Alberta.

The AESO uses Regulating Reserves to maintain the balance between supply and demand. This provides for moment-to-moment changes in load and generation on the system through automated controls. When supply does not equal demand, frequency imbalances occur. The AESO uses Regulating Reserves to restore and maintain the frequency at 60 hertz. The volume of regulating reserve the AESO purchases is based on the load variability in the province.

The AESO uses Contingency Reserves when an incident results in an imbalance between supply and demand and provides a short-term solution prior to the energy market being able to react. Contingency Reserves are determined based on Western Electric Coordinating Committee (WECC) criteria.

Spinning and supplemental reserves are used to maintain the balance of supply and demand when an unexpected system event occurs. These reserves provide capacity the system controller can call on with short notice to correct any imbalance. These reserves can come from the supply side (generators) or from the demand side (load curtailment), both locations where electricity storage systems can play a role.

Spinning reserves are the fastest acting, as they are synchronized with the grid. Supplemental reserves (also known as non-spinning reserves in other jurisdictions) are not typically synchronized to the grid and are slower to respond when called upon.

**Table 1: AESO's Technical Requirements for Operating Reserves [14]**

| | Regulating Reserve | Contingency Reserves | | |
|---|---|---|---|---|
| | | Spinning Resource (SR) | Supplemental Resource (Load) | Supplemental-Generation |
| **Minimum capacity** | 15 MW | 10 MW | 5 MW | 5 MW |
| **Minimum ramp rate** | 10 percent of the max per min | | | |
| **Minimum continuous operation** | 60 min | 60 min | 60 min | 60 min |
| **AS dispatch response** | 15 min | 15 min | 15 min | 15 min |

[14] www.aeso.ca/downloads/Ancillary_Services_Manual.pdf

| | Regulating Reserve | Contingency Reserves | | |
|---|---|---|---|---|
| | | Spinning Resource (SR) | Supplemental Resource (Load) | Supplemental-Generation |
| **Control signal/Directive response time** | 40 sec to short ramp, 28 sec for real power | 10 min | 10 min | 10 min |

## 2.2 Reliability standards

Reliability is the power system components' ability to deliver electricity to all points of consumption, in the quantity and with the quality the customer demands. Reliability standards are a portfolio of standards for the electricity grid and include everything from voltage and reactive control to system operating limits, transmission operations, and protection systems. These standards ensure the bulk electricity system operates reliably.

### 2.2.1 NERC

The North American Electric Reliability Corporation (NERC) administers the reliability standards. The NERC is a not-for-profit, international (USA, Mexico, and Canada) regulatory authority. Its mission is to assure the reliability of the bulk power system in North America by developing and enforcing reliability standards. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) in the United States and governmental authorities in Canada. Reliability standards are enforceable in all interconnected jurisdictions in North America.

### 2.2.2 Alberta Reliability Standards

Alberta implemented the Alberta Reliability Standards (ARS) based on the NERC standards and regional standards the WECC developed. Alberta is not under FERC authority; the AUC approves all ISO rules and reliability standards. Alberta's unique deregulated "Energy Only" electricity market makes it challenging to apply the standard North American wide reliability standards developed by NERC in Alberta.

#### *2.2.2.1 AESO Reliability Plan*

The AESO has the authority to prevent or mitigate emergency operating situations in future analysis and during real-time conditions to preserve the integrity and reliability of the Alberta Integrated Electric System (AIES). This reliability plan describes the reliability functions the AESO performs in operating the bulk electric system, including reliability analysis for current-day and next-day operations, emergency operations, and system restoration.

The AESO monitors real and reactive power system flows, operating reserves, and the status of system elements that could result in violations and/or affect the system's restoration capability. The AESO models and analyses the following to determine any potential System Operating Limit and violations of the Interconnection Reliability Operating Limits:

- the bulk electric system, including all facilities operated at voltages of 100 kV or higher;
- all transmission elements in Alberta operated at voltages greater than 25 kV;
- generation facilities 5 MW or larger, even if distribution connected; and
- generation facilities it considers to be potentially significant (such as facilities associated with large industrial sites that may impact the transmission system).

The AESO ensures Alberta market participants always operate under known and studied conditions. The AESO also ensures market participants return their systems to a secure operating state following contingency events within established timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating, and analysis tools. The AESO works to reconfigure the AIES to within all limits following contingencies within 30 minutes.

Daily, the AESO conducts next-day security analysis, using planned outages, forecasted loads, expected generation patterns, and expected net interchange. The analyses include contingency analysis, voltage stability analysis on key interfaces, and a review of reactive reserves for defined areas when appropriate.

Implementing ESS (flywheels, batteries, CAES, I-CAES, and pumped hydro) could affect many of these calculations and parameters, as a variety of ESS devices could replace or supplement traditional facilities or assist the AESO in avoiding certain situations completely.

### 2.2.3 Standards

There are 14 categories of reliability standards:

- (BAL) Resource and Demand Balancing
- (CIP) Critical Infrastructure Protection
- (COM) Communications
- (EOP) Emergency Preparedness and Operations
- (FAC) Facilities Design, Connections, and Maintenance
- (INT) Interchange Scheduling and Coordination
- (IRO) Interconnection Reliability Operations and Coordination
- (MOD) Modelling, Data, and Analysis
- (NUC) Nuclear
- (PER) Personnel Performance, Training, and Qualifications
- (PRC) Protection and Control
- (TOP) Transmission Operations
- (TPL) Transmission Planning
- (VAR) Voltage and Reactive

Of the 14 categories of reliability standards, a subset (BAL, CIP, EOP, FAC, TOP, TPL) are impacted or benefit from the introduction of storage technology in Alberta based on discussions with the AESO:

- (BAL) Resource and Demand Balancing — maintain steady-state frequency within defined limits by balancing power demand and supply in real time; use contingency reserves to balance resources and demand and return interconnection frequency within defined limits following a disturbance resulting from a loss of supply; and specify the quantity and types of contingency reserve required to ensure reliability under normal and abnormal conditions.
- (EOP) Emergency Preparedness and Operations — the development, maintenance, implementation, and coordination of plans to mitigate operating emergencies.
- (FAC) Facilities Design, Connections, and Maintenance — establish connection and performance requirements and reliability impacts for facilities connecting to the AIES, ensure system operating limits used in the reliable planning and operation of the bulk electric system are determined based on an established methodology.
- (TOP) Transmission Operations — requires the AESO to provide operating data to entities responsible for reliable power system operation so that those entities have the operating data needed to monitor system conditions within their areas; ensure interconnection reliability operating limit exceedances are corrected within established timelines; ensure the AESO operates its major intertie transfer paths to established system operating limits.
- (TPL) Transmission Planning — ensure a reliable transmission system is planned that meets specified performance requirements, with sufficient lead time, as identified by periodically performed system simulations and associated planning assessments.

## 2.3 Alberta's electricity grid emissions

Based on 2014 data, Alberta's GHG emissions are significantly higher than other provinces. In 2014, Alberta contributed over 57 percent of Canada's GHG emissions in the electricity sector. The high coal base in Alberta's generation fleet drives these emissions (see Figure 2).

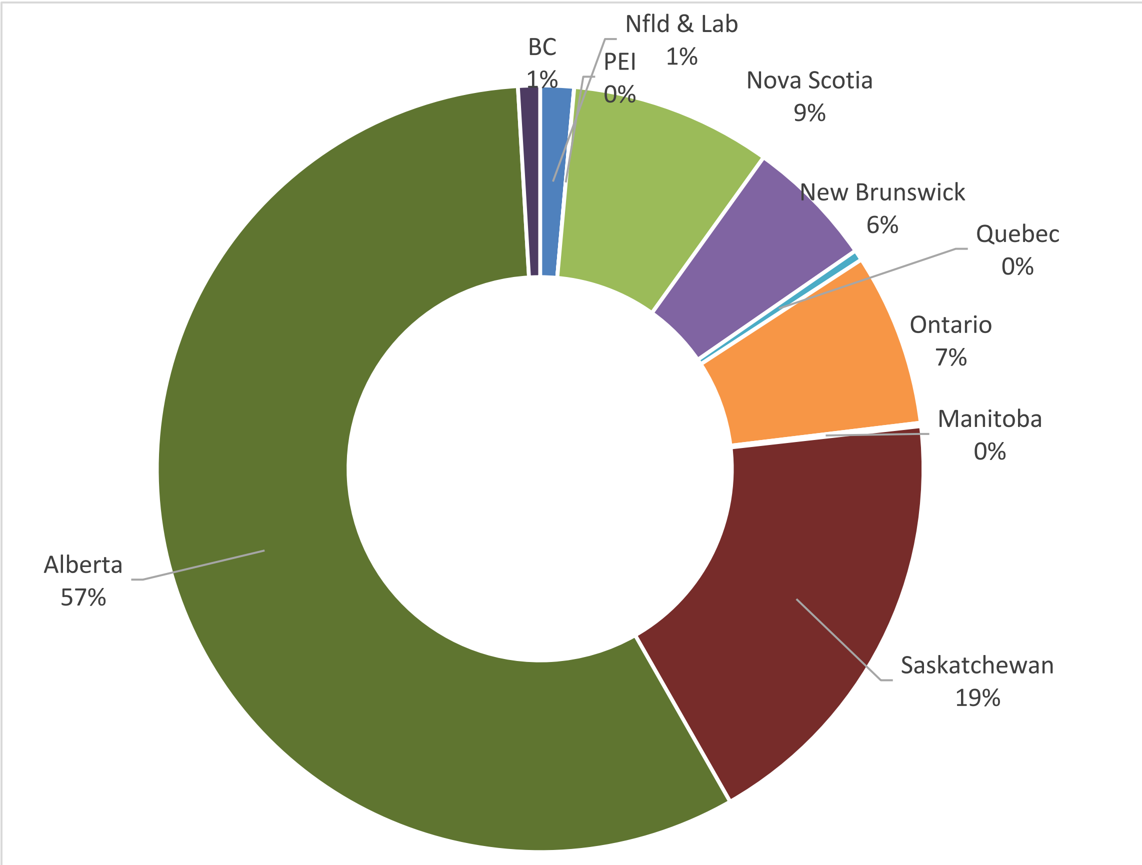


**Figure 2: Canada's Electricity Sector GHG Emissions by Province in 2014 — Source 2016 National Inventory Report**

Grid emissions intensity is measured in tonnes of $CO_2$ equivalent per MWh of electricity generated. Alberta's grid emissions intensity is the highest in Canada based on the same National Inventory Report data (see Figure 3).

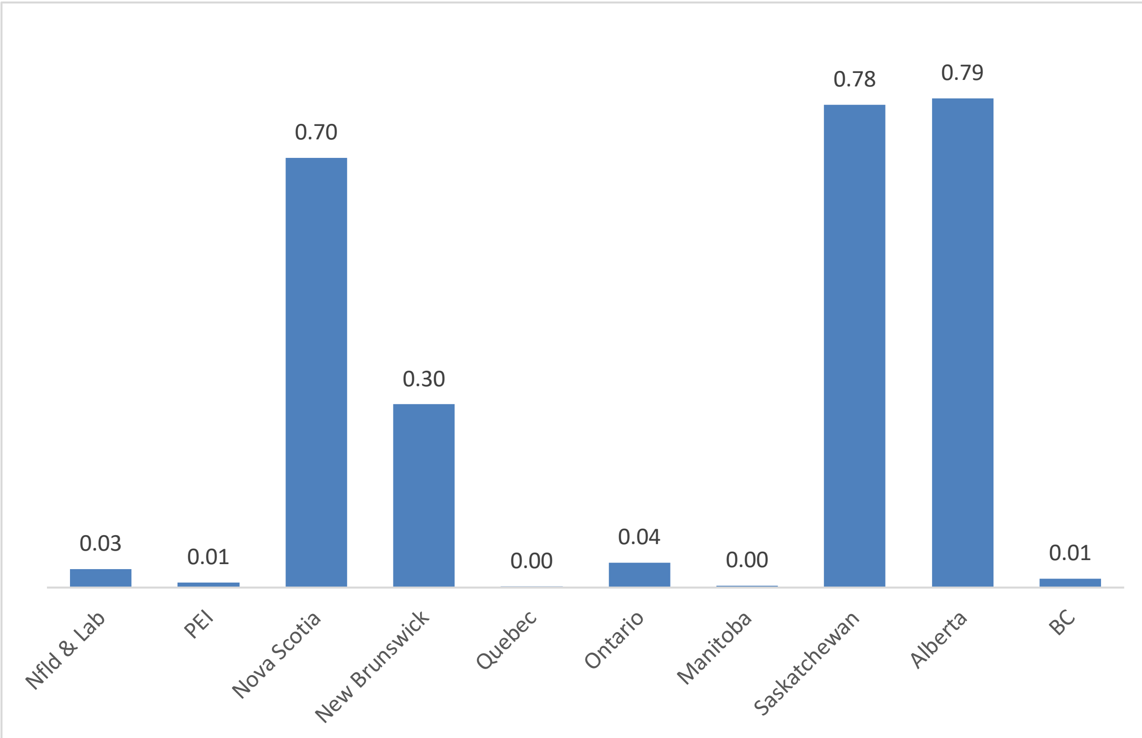


**Figure 3: 2014 Provincial GHG Average Grid Greenhouse Emissions Intensity, (Tonnes CO2e/MWh) — Source National Inventory Report — 2016**

## 2.4 Alberta's renewable energy opportunities

Alberta has sufficient renewable energy resources to power all of Canada's electricity requirements on an energy basis. Alberta's renewable energy resources are abundant, and technologies are mostly commercial or fully mature. Solas sourced the information in Figure 4 from the Jacobs' Energy Potential and Metrics Study that was completed in 2014.

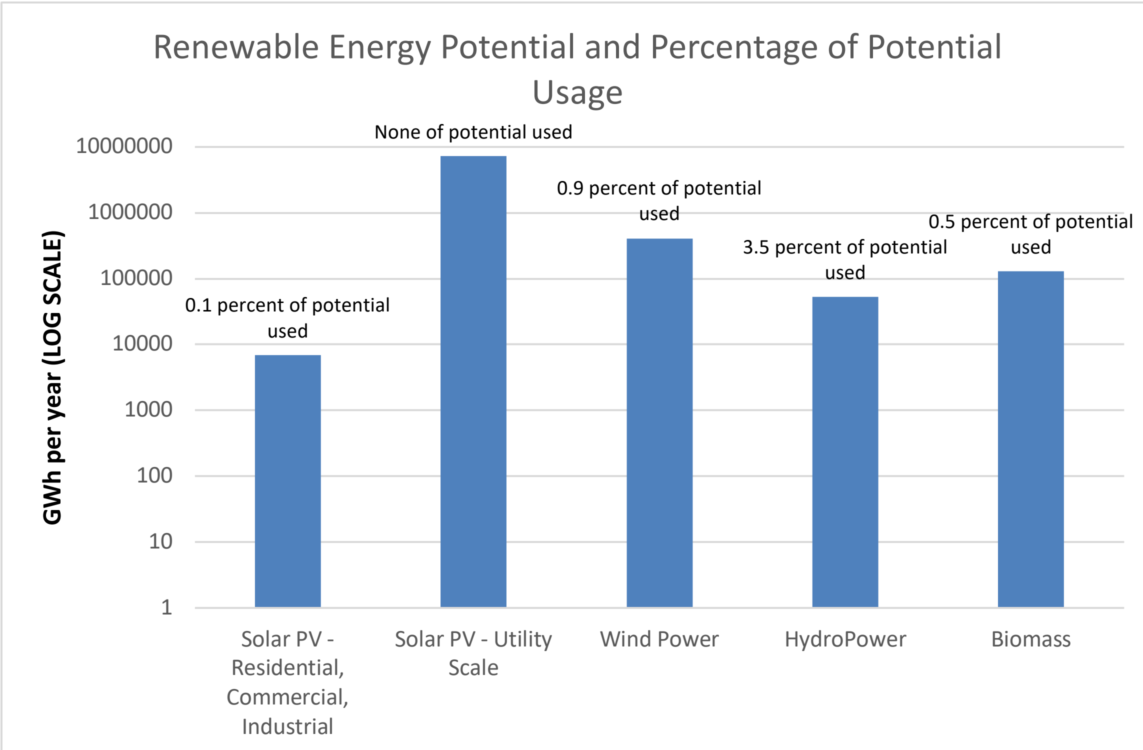


**Figure 4: Alberta's Renewable Energy Potential — Jacobs Study, 2014[15], Solas Analysis**

Technologies suitable for Alberta include:

- solar photovoltaic, concentrating solar power, and solar thermal;
- utility-scale wind power generation and microgeneration wind power;
- hydropower, including large-scale hydropower and run-of-the-river hydropower;
- geothermal power generation, including co-production and low-temperature binary; and
- biomass combustion, gasification, anaerobic digestion, and landfill gas.

When comparing renewable energy technologies, key aspects must be taken into consideration, including the location, production profile, and ability to dispatch. ESS allows for greater dispatch flexibility for some technologies.

Renewable energy resources can be location specific or universally available. For example, in Alberta, solar is universally available; however, it is better in the southern parts of the province. Wind power at the utility scale is available in the province's south, central, and eastern portions, and has limited potential in the north.

[15] Energy Potential and Metrics Study - An Alberta Context, Jacobs Consultancy, 2014

The production profile of renewable energy varies by resource. VG is renewable energy electricity generation that varies seasonally and diurnally. Solar and wind, and to an extent run-of-the-river hydropower, are VG sources (see Figure 5 below). Biomass and large hydropower typically are baseload power generation; however, they may have variances between summer and winter due to resource availability. Geothermal power generation typically does not vary seasonally or diurnally.

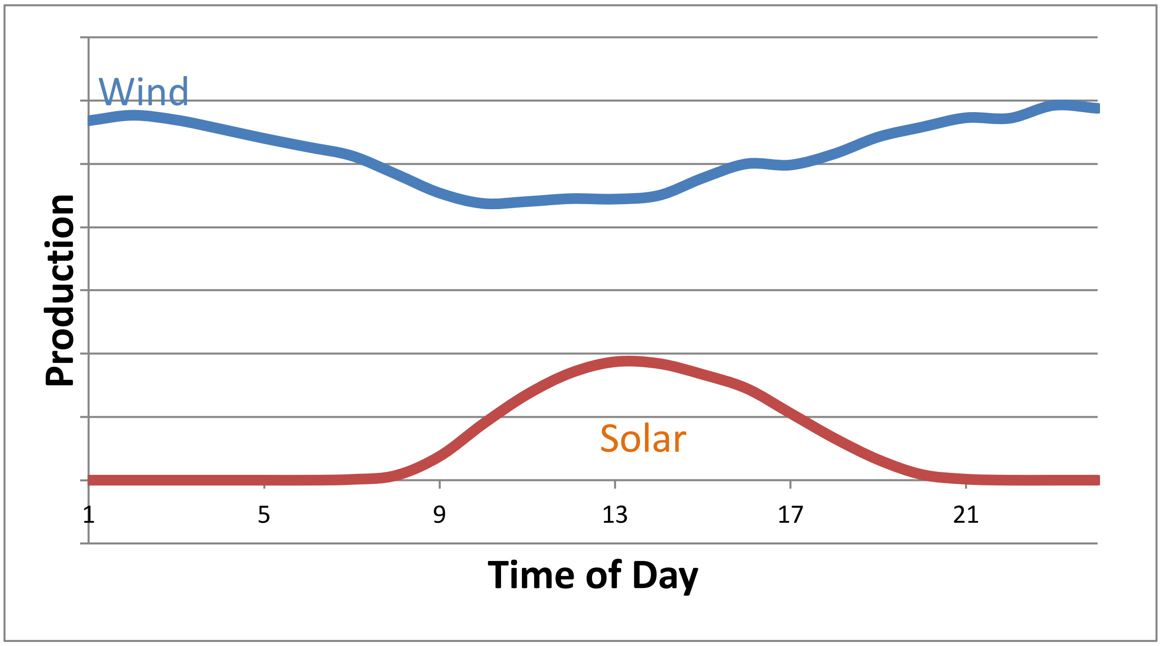


**Figure 5: Illustrative Annual Production Profile — Alberta's Wind and Solar resources are a natural complement to each other — Solas analysis**

The ability to dispatch a resource is often confused with resource variability. All renewable energy resources can dispatch down; however, few can dispatch up. Table 2 compares the generation production profiles, as well as where these generation sources are in Alberta.

## Table 2: Alberta's Renewable Resource, Location, and Production Profile

| | Technology Status | Alberta Location | | | Production Profile | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Distributed Generation | Centralized | Geography | Variable | Peaking | Dispatch-up | Dispatch-down | Baseload |
| Solar PV — Utility | Commercial | | ✓ | Universal | ✓ | ✓ | * | ✓ | |
| **Solar PV — Rooftop (Commercial & Industrial)** | Commercial | ✓ | | Universal | ✓ | ✓ | | | |
| Solar — Concentrating Solar Power | Commercial | | ✓ | South | ✓ | ✓ | * | ✓ | |
| **Wind power — Utility scale** | Commercial | | ✓ | South, central, and east | ✓ | | * | ✓ | |
| Wind power - microgeneration | Commercial | ✓ | | Universal | ✓ | | * | ✓ | |
| **Hydro — Large** | Mature | | ✓ | North | | | ✓ | ✓ | ✓ |
| Hydro — Run-of-the-river | Mature | | ✓ | Varies | ✓ | | * | ✓ | ✓ |
| **Geothermal power** | Commercial | | ✓ | Varies | | | ✓ | ✓ | ✓ |
| Biomass — combustion/gasification | Mature/Commercial | | ✓ | Universal | | | ✓ | ✓ | ✓ |
| **Biomass — Anaerobic Digestion/Landfill Gas** | Commercial | ✓ | ✓ | Universal/Varies | | | * | * | ✓ |

* ESS with these technologies allows the ability to dispatch up to some extent.

Solas has identified Alberta's wind resource and solar resource geographically (see Appendix A-1). Solas extracted the wind resource map from its Canadian Wind Energy Association Wind Vision Technical Overview Report (2013). The Canadian Solar Industry Association provided the solar resource map, which was created by greenpowerlabs (see Appendix A-2)

# 3 STORAGE TECHNOLOGY — AN OVERVIEW

ESS is the process of converting electrical energy from a power network or generation source into a form that can be stored so that, later, it can be converted back into electrical energy. This report focuses on electrical storage systems (ESS) only and does not cover heat storage.

Storage can be applied at three key areas in the electricity supply chain: on-site with generation, on-grid with transmission, or at the customer site with load. The role of ESS varies depending on the location of ESS application.

All ESS has three components: a storage medium, a power conversion system, and a balance of plant:

- Storage medium — This is the energy reservoir that is either mechanical, chemical, heat, or electrical storage.
- Power conversion system (PCS) — The power conversion system modifies the current between alternating current and direct current.
- Balance of plant — This includes the facilities that house the ESS, substation, access roads, communication system, and HVAC system.

ESS technologies that provide capacity over a short period have fundamentally different applications than technologies that provide long duration of sustained energy. Storage applications with duration of less than one hour are labelled as Power Applications, while those with a duration longer than one hour are labelled Energy Applications. Think of these as the difference between sprinters and marathoners. Power storage ESS provide short bursts of fast response electricity at high capacity, whereas energy storage ESS provide energy release for significant durations. For this report, Solas separated power and energy services at one hour consistent with literature.

## 3.1 Storage Technologies

The following are key characteristics of storage systems important to understanding the differences between technologies.

Storage Capacity[16] is the quantity of energy available in the ESS after charging. In some systems, such as BESS, discharge is often incomplete. The depth of discharge limits the total usable energy. Typically, in BESS, the capacity reduces with increased number of cycles.

Storage System Power[17] is the discharge rate under normal circumstances.

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[16] Ilinca, Hussein Ibrahim and Adrian. 2013. Energy Storage - Technologies and Applications. January 2012. Croatia. Published by Intec.
[17] Ilinca, Hussein Ibrahim and Adrian. 2013. Energy Storage - Technologies and Applications. January 2012. Croatia. Published by Intec.

Efficiency refers to the amount of energy that comes out of the storage relative to the energy put into the storage. Losses occur in the ESS process through energy transfer and conversion. Typical values for efficiency include between 60–70 percent for conventional batteries, 75–85 percent for advanced batteries, 73–80 percent[18] for compressed air energy storage (CAES), 75–80 percent for pumped hydro, 80–90 percent for flywheel storage, and 95 percent for capacitors and superconducting magnetic energy storage (SMES).[19] Technology development has improved the efficiency of ESS and will continue to improve over time.

Cycle life is the number of times a storage technology can release the energy it was designed to do after each recharge. One cycle is one charge and one discharge. This is critical for BESS where the storage medium discharge rate affects the cycle life. The storage medium can be replaced during the life of the storage system; however, the operating costs then increase.

Response time is the delay between a signal sent to the ESS and the time for the ESS to start to respond. Most response times are several seconds or less.

Ramp Rate is the change in power output over time. Ramp rates vary significantly by technology type.

Charge Rate is the change in charge over time. This is important since if storage cannot recharge quickly, then it may not have the required energy for the required service.

The key types of ESS as shown in Figure 6 are as follows: chemical, mechanical, electrical energy, and thermal storage. ESS differ significantly in their technology, size, capabilities, and capital and operating costs. ESS scalability, power capacity, energy storage capacity, cycle life, temperature dependences, depth of discharge, ramp rates, and response time also differ. Like selecting an automobile, the choice highly depends on the foreseen usage.

- Chemical energy storage includes electrochemical energy storage, such as batteries like lead-acid, nickel metal hydride, lithium ion, flow cell batteries, and storage such as fuel cells and thermochemical energy storage (hydrogen, metals, ammonia).
- Mechanical energy storage includes kinetic energy storage such as flywheels, and potential energy storage such as pumped hydro energy storage and CAES.
- Electrical energy storage includes capacitors and supercapacitors, as well as magnetic/current energy storage, including SMES.
- Thermal energy storage includes low- and high-temperature storage.

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[18] Efficiency calculation for CAES includes the energy from natural gas and electricity use.
[19] Ibrahim and Illinca, Techno-Economic Analysis of Different Energy Storage Technologies, Chapter 1 — page 13.

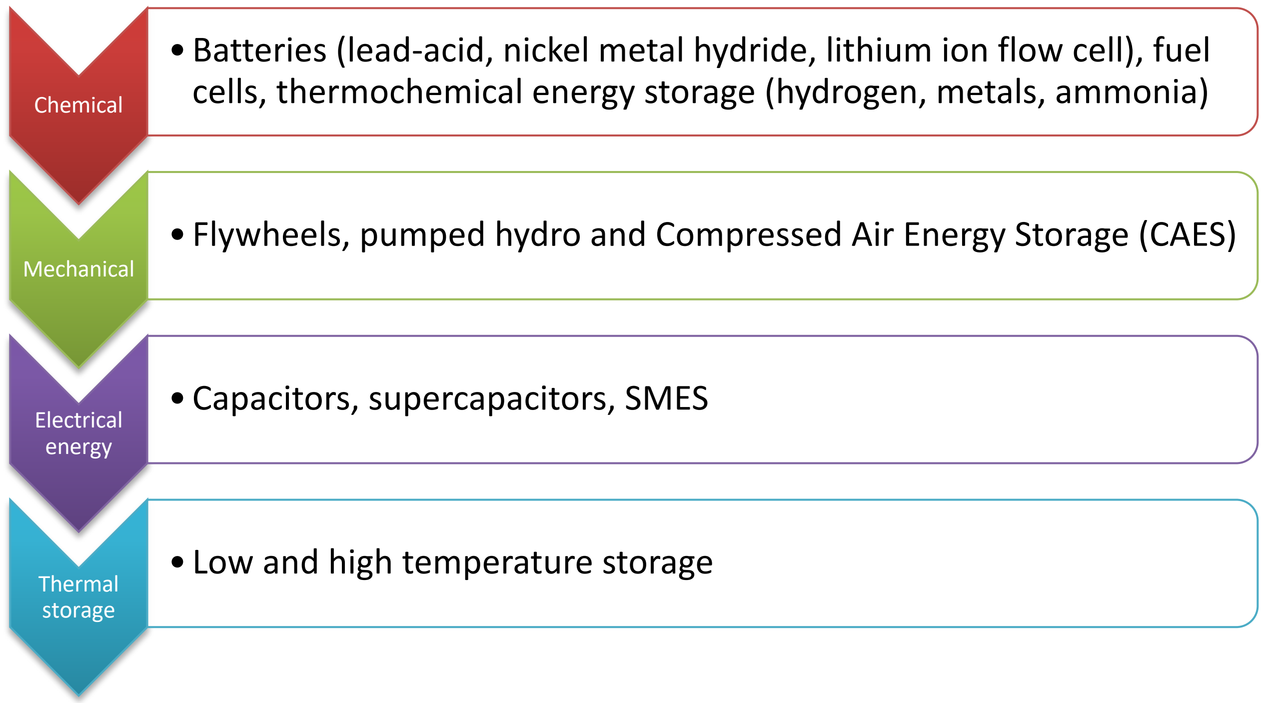


**Figure 6: Types of Energy Storage**

The Sandia National Laboratories Global Energy Storage Database[20] lists 51 types of ESS technologies within the major categories. These include operational or under-construction storage technologies. The database identifies 149 GW of operational storage as of May 2016. Pumped Hydro Storage represents 97 percent of all operational ESS worldwide. Thermal storage, electro-chemical, and electro-mechanical each represent 1 percent of the installed capacity. Hydrogen storage is limited in its application. Per the Sandia database, pumped hydro storage accounts for most storage facilities announced or under construction.

Chemical energy storage using Lithium Ion technology has the largest installation base of all electro-chemical based energy storage. Lead-acid batteries have the highest percentage of decommissioned facilities compared to other electrochemical energy storage technologies. The countries with the highest capacity of electrochemical storage installations are USA (33 percent), South Korea (22 percent), Japan (20 percent), and Germany (7 percent). Canada has 1 percent of the installed worldwide capacity of operational electro-chemical energy storage installations.

CAES has the largest installation base of any electro-mechanical storage technology. Molten salt thermal storage has the highest installed base of all thermal storage technologies.

[20] www.energystorageexchange.org/projects

Solas presents a high-level overview of each of the following types of energy storage technologies: batteries, CAES, pumped hydro, and flywheels, including an introduction to current installations in North America.

### 3.1.1 Batteries

Batteries generally refer to multiple technology types that convert chemical energy into electrical energy. Electrochemical cells are the building blocks of batteries. Each cell has an anode and cathode. Electrolytes allow the ions to move between electrodes and the anode/cathode.

Batteries do not have geographic restrictions; however, most require climate control. There is a wide range of technologies used in batteries. Cycle life is typically the largest issue for batteries.

The technology is divided into solid-state batteries and flow batteries. Solid-state batteries include technologies such as: Lithium Ion, Nickel Cadmium, Sodium Sulfur, Lead-acid, and a growing number of additional technologies. While lead-acid batteries are technologically mature and relatively cheap to produce, they have a rather short-lived life span. Lithium-ion batteries have the highest energy density in commercially available batteries and have high efficiencies, but the battery deteriorates even if it is not used. Complete discharge tends to destroy the storage cells. In 2010, sodium sulfur was the most widely deployed battery, with more than 270 MW installed at that time.

Flow batteries include technologies such as: Redox flow batteries, Iron-Chromium Flow Batteries, Vanadium Redox Flow Batteries, and Zinc-Bromine Flow Batteries. Flow batteries have high power and energy capacity, fast recharging, long life, and full discharge.

### 3.1.2 Compressed air energy storage

CAES uses electricity produced to pressurize air into a reservoir. This air is then released to power turbines and produce electricity. There are three types of compressed air technologies: diabatic compressed air energy storage (d-CAES), advanced adiabatic compressed air energy storage (aa-CAES), and isothermal compressed air energy storage (i-CAES):

- d-CAES — Compressed air is stored underground. When electricity is required, the pressurized air is heated and expanded in an expansion turbine driving a generator for power production. There are two d-CAES plants in the world: one in Germany and the other in the USA. These plants use conventional natural gas turbines and natural gas to warm the decompressed air and generate additional power. The overall energy efficiency is approximately 42 percent without waste heat use and 55 percent with waste heat use.
- aa-CAES — Advanced adiabatic compressed air energy storage efficiency can be as high as 70 percent if the heat of compression is recovered and used to reheat the compressed air during the turbine operations. This reduces the requirement to burn natural gas to warm the decompressed air. The heat is stored in technology such as

thermal oil or molten salt. A pilot plant is scheduled to start operations in 2018 in the USA.[21] Efficiencies are expected to be more than 70 percent.

- i- CAES— This emerging technology tries to overcome some of the issues with both adiabatic and diabatic-CAES. Less energy is wasted during the compression process if the compressed air is kept at a constant temperature. This yields higher round-trip efficiencies. There are no commercial i-CAES facilities implemented; however, some have been proposed. Quoted efficiencies of this technology are around 70–80 percent.

CAES can store large amounts of energy and has fast response times; however, it typically requires sealed storage caverns.

### 3.1.3 Pumped hydro

Pumped hydro is the only technology that has been deployed at a gigawatt scale. Pumped hydro storage uses bodies of water at differing elevations. During discharge hours, the water is flowed from the higher elevation to the lower elevation and generates electricity through a hydroelectric facility. The water is then stored in the lower reservoir. The system is recharged using electricity to pump the water up to the higher reservoir.

Selecting the right geography and climate to locate pumped hydro is critical. Locations that have heavy rainfall may limit the ability to access the storage. Pumped hydro is fast reacting and has energy efficiency of approximately 65–80 percent. Storage capacity depends on the size of the reservoir and the elevation difference. The key challenges are the limitation of suitable sites, large environmental impacts, and requirement for a large water source.

The USA has approximately 20 GW of pumped hydro energy storage. Alberta does not have any pumped hydro energy storage facilities, though some have been proposed in the foothills of the province[22].

### 3.1.4 Flywheels

Flywheels store energy in the form of kinetic energy, through a rotating mechanical device. The key attribute of the flywheel is that it can deliver this energy almost instantaneously. The flywheel has a motor that drives a spinning mass in the centre. Flywheels have excellent cycling capacity. Flywheels have low maintenance and long lifespans. They have extremely fast response times; however, they have low storage capacity. They have high self-discharge rates between 3 percent –20 percent per hour, making long-term storage infeasible. Flywheels are well suited for frequency regulation.

[21] www.energystorage.org, Sourced May 23, 2016
[22] http://www.turningpointgeneration.ca/projects.html

The storage capacity associated with each technology type are shown in the figure below. Storage capacity is important since it affects the emissions, services provided and technology available.

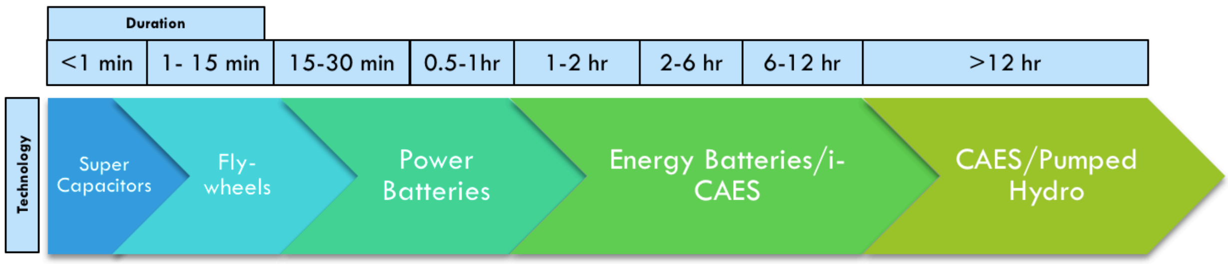


**Figure 7: Comparison of Technologies for Storage Capacity (Hours)**

## 3.2 Current installations in North America

The USA and Canada have a combined total of 21 GW of storage. Most installations are pumped hydro storage (20 GW) in the USA. In comparison to Canada, the USA has over 100 times the installed energy storage.

**Table 3: Operational Energy Storage Systems Rated Power (kW) in Canada and USA as of May 2016 — Reference Sandia Database**

| Storage Type and Size (kW) | Canada | United States | Grand Total |
|---|---|---|---|
| | kW | kW | kW |
| Electro-chemical | 10,352 | 416,828 | 427,180 |
| Electro-mechanical | 2,660 | 171,150 | 173,810 |
| Pumped hydro storage | 174,000 | 20,355,700 | 20,529,700 |
| Thermal storage | 1,515 | 663,501 | 665,016 |
| **Total** | **188,527** | **21,607,179** | **21,795,706** |

The USA electro-chemical and electro-mechanical technology projects have been deployed mostly in the Pennsylvania-New Jersey-Maryland (PJM) ISO, (240 MW), followed by Electric Reliability Council of Texas (ERCOT) (50 MW). PJM ISO installations are mostly third-party ownership models, with few utility-owned installations. Customer-owned installations are more plentiful than utility-owned. However, the rated power size of the storage is smaller per installation.

Canadian installations are small by comparison, and much of the energy storage is pump hydro storage in Ontario. Most of the electro-chemical and electro-mechanical energy storage is also deployed in Ontario.

Alberta's only storage project listed in the Sandia database is thermal storage at Drake's Landing in Okotoks. Solas' understanding is that the City of Calgary used flywheels for energy storage at data centres and emergency operations locations. The table below identifies the Canadian applications of energy storage.

**Table 4: Canada's Energy Storage Installations — Sandia Database May 2016**

| | Electric Bill Management | Electric Bill Management with Renewables | Electric Energy Time-shift | Electric Supply Capacity | Frequency Regulation | Grid-Connected Commercial (Reliability and Quality) | RE Capacity Firming | TOTAL (kW) |
|---|---|---|---|---|---|---|---|---|
| Alberta | | | 1,500 | | | | | 1,500 |
| Thermal | | | 1,500 | | | | | 1,500 |
| BC | | | | 1,000 | | 1,000 | | 2,000 |
| Li Ni Mn Co battery | | | | | | 1,000 | | 1,000 |
| Na-S battery | | | | 1,000 | | | | 1,000 |
| NWT | | | | | | 1100 | | 1,100 |
| Li-ion battery | | | | | | 1100 | | 1,100 |
| Ontario | 150 | 2 | 174,675 | | 6,000 | 500 | | 181,327 |
| Compressed air | | | 660 | | | | | 660 |
| Flywheel | | | | | 2,000 | | | 2,000 |
| Ice thermal | | | 15 | | | | | 15 |
| Li Fe phosphate battery | | | | | 4,000 | | | 4,000 |
| Li polymer battery | | | | | | 500 | | 500 |
| Li-ion battery | 150 | 2 | | | | | | 152 |
| Pumped hydro (open loop) | | | 174,000 | | | | | 174,000 |
| PEI | | | | | | | 1,000 | 1,000 |
| Na-Ni-Cl battery | | | | | | | 1,000 | 1,000 |
| Quebec | | | | 1,200 | | | | 1,200 |
| Li-ion battery | | | | 1,200 | | | | 1,200 |
| Sask | | | | | | | 400 | 400 |
| Li-ion battery | | | | | | | 400 | 400 |
| **TOTAL (kW)** | **150** | **2** | **176,175** | **2,200** | **6,000** | **2,600** | **1400** | **188,527** |

## 3.3 Technology maturity

The technical maturity of each energy storage technology varies significantly. Pumped hydro energy storage and lead-acid batteries are fully mature and have been used for many decades.

Some technologies are developed but not considered mature. These include CAES, NiCad, NaS, ZEBRA, Li-ion, Flow Batteries, SMES, flywheel, Capacity or, Supercapacitor, and some thermal energy storage systems. Developing technologies include fuel cells, metal-air batteries, and i-CAES.

## 3.4 Alternative technologies and solutions to energy storage

Other technologies can provide the same role as energy storage services. The following lists five other technologies, natural gas peaking units, large scale hydro, interconnection to neighbouring jurisdictions, curtailment and load shed service that can provide benefits like energy storage facilities.

### 3.4.1 Natural gas peaking units

Natural gas peaking units can provide frequency regulation and firming for renewable energy. The benefit of natural gas peaking units is fast ramp rates. However, the environmental footprint of these facilities is significant and is approximately 0.50–0.67 Tonnes $CO_2e$/MWh[23].

### 3.4.2 Large-scale hydro development

Large-scale hydropower provides capacity, fast response, a large volume of energy, and has significant advantages. This power generation is dispatchable. The concern with large-scale hydro development is the environmental impacts, including their GHG emissions[24]. Impoundment and pumped hydro storage facilities can alter the amount and quality of water downstream, affecting plant and animal species. Dams affect fish migratory routes. Thus, several large-scale hydro facilities have been removed in recent years.

### 3.4.3 Interconnection to neighbouring jurisdictions

Alberta has limited interconnection capabilities with neighbouring jurisdictions. The Alberta-BC Intertie and the Montana-Alberta Tie Line (MATL) are the major interties for import and exports. The Alberta-Saskatchewan tie line is limited in its capability.

The ability to import power from other jurisdictions provides similar benefits to energy storage. While these interties allow Alberta to import energy over long durations, the import requirements are based on the energy market merit order (EMMO) and, therefore, require a two-hour dispatch timeline.

[23] February 2009 Industry Provincial Offset Group – *IPOG- Quantifying Electricity Grid Emissions in Canada*, List of Facilities for Recently Commissioned Intensity Calculations A-32

[24] Teodoru, C. R., J. Bastien, M.-C. Bonneville, P. del Giorgio, M. Demarty, M. Garneau, J.-F. Hélie, L. Pelletier, Y. T. Prairie, N. Roulet, I. Strachan and A. Tremblay. 2012. "The Net Carbon Footprint of a Newly Created Boreal Hydroelectric Reservoir." Global Geochemical Cycles, Vol. 26, GB2016, DOI:10.1029/2011GB004187

Long-term energy storage potential with British Columbia allows for power to be exported and stored within the large hydropower facilities and imported to Alberta later. This offers a solution for long-term supply/demand. However, it has intra-hour requirements that the interties cannot meet.

### 3.4.4 Curtailment

In 2009, the AESO introduced wind power into the AIES, using the Market and Operational Framework for Wind Integration in Alberta[25]. This framework integrates wind power using a combination of wind forecasting, the energy market merit order, regulating reserves, and other methodologies. The AESO identified wind power management (curtailment) as a key tool for integrating wind power. This framework identified that the system operator can issue directives to market participants as required to prevent a threat to system security or to return the AIES to a safe and reliable state.

To the extent that the energy market and the available regulating reserves are insufficient to maintain reliability, then-out-of-market actions, including curtailments, can be used to ensure compliance with industry reliability standards. Wind power generators are at risk of curtailment due to these potential conditions:

- forecast loss of wind power and insufficient ancillary services or ramping services;
- supply surplus conditions ($0 offer dispatch);
- insufficient ancillary services;
- unforeseen wind conditions, such as microbursts; and
- disturbance and emergency conditions where wind may be dispatched off during islanding conditions, or emergencies where the variable nature of wind power generation cannot be tolerated .

Per the 2009 report, wind generation was previously only curtailed to manage transmission constraints and other reliability events but not for market situations. This framework integrated the AESO's ability to curtail wind to also manage market situations.

Therefore, curtailment of variable renewable energy provides similar response to some aspects of energy storage.

### 3.4.5 Load Shed Service

Under Section 303.1 Load Shed Service, the system operator can shed load in the event there is insufficient generation to meet load. This provides negative supply and, therefore, can operate like an energy storage device.

[25] www.aeso.ca/downloads/WI_Paper-_Final.pdf

# 4 RELEVANT ENERGY STORAGE STUDIES

There is a wealth of literature on energy storage. A summary of several relevant reports follows.

## 4.1 Canadian-based studies

### 4.1.1 Phase Two Wind Integration, Recommendation Paper — Alberta Electric System Operator — 2012

The AESO has been proactive about integrating wind generation into the AIES. Phase II of the wind integration process refers to wind development beyond 1500 MW of installed capacity. The AESO presented two recommendations:

- allow wind to be dispatchable via the EMMO; and
- explore a new system ramping service.

The AESO developed these recommendations through discussion with industry groups after initially presenting several other options.

The system operator already dispatches wind in several other ISOs in North America, all with different rules. This paper proposes that, for Alberta, the AESO develop rules and guidelines to allow wind to be initially dispatchable on a voluntary basis, and to consider mandatory dispatch later.

The AESO conducted a Wind Dispatch Pilot, using two TransAlta facilities with a combined capacity of 134 MW. A key feature of the program allows the generator to restate offer volumes to the merit order as wind conditions change. The AESO tested three levels of restatement limits: 20 minutes pre-dispatch, 10 minutes pre-dispatch, and no time limit. The pilot resulted in an average curtailment of 1.5 percent at the 20-minute level, and 0.2 percent at the no-limit level. Overall, the pilot improved System Controller visibility of wind generation. Wind facilities can voluntarily participate in the energy market merit order.

The recommendation to explore a ramping service was driven by observed and predicted levels of Area Control Errors (ACE events) that result from wind ramping events. An ACE event is an unscheduled flow of power, either into or out of British Columbia caused by supply/demand imbalance with Alberta. NERC reliability standards determine the acceptable frequency of ACE occurrences and volumes.

The AESO deals with wind power ramps by over-dispatching units to achieve ramp rate and/or through regulating reserves. When the AESO dispatches high ramping units, it introduces considerable volatility into the Alberta Power pool price, and there is additional wear and tear on units that must ramp quickly in one direction then ramp in the other direction as the slower units in the merit order catch up. The AESO would use the system ramping service when the ramp capability of the merit order could not keep up with the ramp required by wind and other system components. A key component of the ramping service is that it provides a market-based solution to a system problem.

The paper also recommends that the AESO investigate a "Pay for Performance" element that encourages quicker and more accurate technologies to participate in the regulating reserve market. The AESO has not proposed specifics for either the ramping service or pay for performance standards for stakeholder comment.

### 4.1.2 Energy Storage Integration, Recommendation Paper — AESO — 2015

In June 2015, the AESO released a recommendation paper on energy storage. At the time, there were three energy storage projects requesting access to the AIES. The paper addresses three priorities that the AESO developed from stakeholder sessions:

- develop technical requirements to connect and operate,
- determine tariff rate, and
- review technical requirements for Operating Reserves.

For connection and operation technical requirements, the AESO recommends that specific rules be developed for batteries, as existing requirements address other types of storage such as CAES and pumped hydro. The AESO filed rules 502.13 and 502.14 with the AUC in March 2016; the rules became effective April 25, 2016.

The AESO indicates that the appropriate tariff for energy storage is a complicated problem. Generally, facilities within the AIES are classified as transmission, generation, or load; energy storage does not fit exactly into any category.

For the AESO to consider a storage facility for transmission, it would have to file a Needs Identification Document (NID) with the AUC. If the AUC approves it, the facility would be eligible for cost recovery on a regulated, cost-of-service basis, but it could not participate in the energy or ancillary services markets.

In this paper, in most cases, the AESO indicates that energy storage could be viewed as a generator when discharging and load when charging. As a generator, the facility pays Supply Transmission Service (STS), which covers system losses. As a load, the facility pays Demand Transmission Service (DTS), which is the mechanism for recovery of transmission system costs. For energy storage projects, DTS charges are significantly higher than STS charges[26]. Therefore, the AESO studied energy storage operations and dispatch behaviour to inform the appropriate

[26] Tables 16 – 19, Energy Storage — Making Intermittent Power Dispatchable, A Reynolds, Alberta Innovates — Technology Futures, 2011.

application or modification of rate classes or whether a new rate class is needed. The AESO study and tariff proposal was released in June 2016[27] and is reviewed in the next section.

AESO is revising the rules governing operating reserve products to reflect the participation of energy storage technologies. It is expected that, for the purposes of regulating reserves (RR), the AESO will allow storage facilities to include the full range from maximum charge rate to maximum discharge rate. For example, an 8 MW battery can offer 16 MW of regulating range, which is greater than the 15 MW RR requirement, and, therefore, qualifies to participate in the RR market.

The AESO discusses two further issues in its paper: the OR volume requirement and the OR duration requirement. The AESO requires RR providers to supply a range of at least 15 MW for one hour, and supplementary reserves (SR) providers must provide at least 10 MW of capacity for one hour. The AESO's analysis concluded that reducing the volume requirement is not advisable now.

### 4.1.3 AESO 2017 ISO Tariff Consultation — AESO — 2016

In July 2016, the AESO presented their AESO 2017 ISO Tariffs as part of the consultation process for new tariffs. Part of this presentation dealt with Energy Storage tariff treatment. The purpose of the presentation was to share information prior to the AESO filing the 2017 ISO tariff application and to receive feedback. The AESO presented the high-level results of the University of Calgary dispatch study and indicated that rate DTS charges had a small impact on power flow for arbitrage purposes.

The AESO concluded that cost causation considerations for energy storage were similar in the study to those for load; if energy storage charges during system peak, then this could cause bulk system costs, and the same for regional system costs. Charging of energy storage incurs costs for contingency reserve volumes, transmission constraint rebalancing, voltage control charge and other system support services. The AESO concluded that therefore rate DTS applies in the hours in which an energy storage facility is charging, and Rate STS applies in the hours in which it is discharging. Avoiding system peak is the key determination for reducing Rate DTS. The AESO further indicated that the combination of Rates DTS and STS are appropriate for sites that include load and generation.

The Total Rate DTS charges are made up of monthly rate DTS connection charge and monthly rate DTS Ancillary Services Charges. In combination, they can be up to $320,000 per month ($3.9 million annually). The largest portion of the charge is from the monthly rate DTS connection charge (at approximately 90 percent of the total DTS charge).

According to the AESO, for a 20 MW storage facility, the monthly rate DTS connection charge could be as much as $280,000, or an annual rate of approximately $3.4 million. The rate can be reduced by avoiding system peak, owning your own substation, contracting for both DTS and STS

[27] http://www.aeso.ca/downloads/AESO_2017_General_Tariff_Application_-_AESO_Consultation_Invitation_2016-07-07.pdf

and holding charge to 50 percent of the maximum. Most the Monthly Rate DTS Connection Charge costs in these situations are from the regional system.

The Monthly Rate DTS Ancillary Services Charges can be in the range of $40,000 per month ($480,000 annually). Again, the same methods can be used to reduce charges including avoiding system peak, owning your own substation, contracting for both DTS and STS and holding the charge to 50percent of the maximum. The largest portion of the charge is for operating reserves.

The AESO concluded that the AESO will propose Rate DTS will apply to energy storage facilities when charging and indicated that stakeholders could have an opportunity to ask information requests and submit evidence on other approaches during the regulatory proceeding before the Commission which will be filed in Q1 2017.

### 4.1.4 Modelling Dispatch Operations of Energy Storage Facilities — University of Calgary — 2016

The University of Calgary performed a study on behalf of the AESO to examine how energy storage facilities may operate in the Alberta market. The purpose of the study was to provide data to the AESO and not to give direction on tariff treatment. The model assumed an arbitrage algorithm to maximize operating profit and ancillary services were not included. Five technologies were examined: two conventional battery chemistries, flow battery, pumped hydro and compressed air.

Generally, the study found that arbitrage-motivated storage would charge during low demand (usually overnight) and discharge during high demand (usually during the day).

The study also calculated the impact of Rate DTS charges on energy storage economics. Consideration of DTS had only a small impact on revenue, but operating costs were increased by 45 percent resulting in a 16 percent decrease in operating profit.

### 4.1.5 Energy Storage, Unlocking the Value for Alberta's Grid — Alberta Storage Alliance — 2016

The Alberta Storage Alliance (ASA) is a newly formed consortium of technology developers, project developers, utilities, research groups, energy consultants and power generators. They issued a white paper in 2016 that identified that energy storage can play an important role in transitioning away from coal and towards renewables. The paper provides recommended policies and strategies for implementation of storage projects in Alberta.

They indicate that four areas require attention as renewable generation is built and coal power generation is retired; renewable energy integration, price volatility, supply adequacy and grid reliability. ASA notes that energy storage can address these challenges. ASA indicates that barriers to implementation of energy storage include insufficient market signals, market rules that punitively double charge storage, lack of ancillary services market to take advantage of system frequency issues, current regulation and market models stifling value from the instantaneous response capability offered by storage.

ASA recommends:

- conducting a Needs Identification process to determine what services are required to help maintain a reliable electric grid going forward;
- conducting an assessment on system stability services being exempt from certain investment prohibitive tariffs;
- revision of the AESO market rules to allow energy storage to participate in the energy and ancillary services market;
- AESO system planning to allow a non-wires solution for transmission upgrades;
- streamlining the process for expediting behind-the-meter energy storage interconnections for residential and industrial customers; and
- allocation of funds to accelerate deployment of technologies offering GHG emissions reduction benefits.

Notably, ASA indicates that energy storage is an enabler of carbon emission reductions through storage of renewable generation during off-peak hours and deployment during on-peak hours. In addition, ASA notes that energy storage can enable micro-grid solutions and unlock environmental benefits resulting from reduced dependence on diesel fuel.

ASA Appendix 3 provide a summary of the best practices in other North American jurisdictions for recognizing the value that storage can bring to their grids and developing supportive regulations.

### 4.1.6 Energy Storage: Making Intermittent Power Dispatchable — Alberta Innovates Technology Futures — 2011

Alberta Innovates Technology Futures' (AITF) first of two papers on energy storage includes technical descriptions of eight energy storage technologies and economic modelling of two technologies. AITF's economic model uses historical power prices and includes two energy storage applications: arbitrage and capacity firming. AITF limits the modelling to storage facilities co-located with a wind farm and charged only from wind generation. AITF assumes each of the storage facilities has a charge and discharge capacity equal to 60 percent of the wind farm capacity and seven hours of energy storage capability. AITF also assumes that the energy storage facilities would not have an impact on power prices.

The results show that revenue increase from arbitrage could be 15–43 percent, depending on the technology and wind production profile. CAES generated more revenue than the battery due to the efficient use of natural gas. The modelling of capacity firming assumes that wind farms would be required to offer volumes into the Alberta energy market in the same manner as other generators, and calculated instances where the delivered energy did not comply with the offer. Energy storage resulted in a significant decrease in the number of non-compliance hours.

AITF calculates DTS and STS charges and shows that DTS charges would reduce storage revenue by 30 – 50 percent, while STS charges were less than 3 percent of revenue.

### 4.1.7 Techno-economics of Energy Storage — Alberta Innovates Technology Futures — 2014

The second paper expands energy storage modelling to include power-to-gas storage technology, merchant arbitrage, and dynamic power price impacts. The results of this paper show:

- Power-to-gas did not experience as large an economic benefit as the battery or CAES technologies.
- The ability to charge the storage from the grid (merchant arbitrage) added significant value compared to limiting charging to wind farm generation.
- Including dynamic price impacts reduced the arbitrage revenue by over $5/MWh, while the average Alberta Power Pool price was reduced by $2/MWh.
- There is a small revenue benefit from operating reserves markets based on the OR market structure.

In combination, the two AITF studies demonstrate that the revenue potential for energy storage using arbitrage comes close to being sufficient to support investment. However, the AITF did not reach a firm conclusion on the profitability due to uncertainty in energy storage costs.

### 4.1.8 IESO Report: Energy Storage — Independent Electric System Operator — 2016

The Independent Electric System Operator (IESO) in Ontario issued two Request for Proposals (RFP) for energy storage. As of March 2016, 6 MW were installed, with another 6 MW under construction and several more projects under development. The RFPs' purpose was to determine if energy storage could provide time-shifting, load-following/ramping regulation, and operating reserve services to the Ontario power market. The paper reviews technologies that would return electricity to the grid, technologies that would be used for other purposes that would still displace electricity demand (i.e., heating or cooling), and technologies that stored energy for a completely different purpose (i.e., electric vehicles).

Generally, the paper finds that procurement processes based on a system service need is better than procurement for a specific technology, as various technologies often provide the needed service. They would then compete, resulting in better value for the IESO. The paper also recommends that project proponents consider storage technologies capable of providing several services, as they have a higher likelihood of being profitable than technologies that provide only one service.

The question of time-shifting in Ontario is a long-term one, as the province has surplus baseload generation up to 66 percent of the time. The paper concludes that most energy storage technologies are not appropriate, as the common cycling time of those technologies are in minutes or hours to days, not the weeks or months needed to offset the surplus baseload generation.

The IESO found many different energy storage technologies can provide regulating service, ramping, or operating reserves. Ontario's geographic location is an important consideration, as some applications may exacerbate transmission congestion issues.

### 4.1.9 Pan-Canadian Wind Integration Study — GE Energy Consulting Group — 2016

The Pan-Canadian Wind Integration study identified the implications of increased wind generation integration in the provincial electricity markets. The study included operational implications for the current and future electric grid infrastructure.

The Pan Canadian Wind Integration Study examined four scenarios for wind integration levels across Canada from 5 percent to 35 percent in 2025. The study included models of the entire Eastern and Western interconnections – effectively all ten provinces plus the continental United States except Texas.

The study found that hydro generation is a useful complement to wind generation, but that inter-provincial transmission upgrades would be essential to limit curtailment. Further, increases in regulation reserve requirements are small compared to the volume of wind generation installed. In Alberta, for example, 1,000 MW of increased wind generation requires just 25 MW in increased regulating reserves.

The study identified curtailment rates greater than 6 percent at 20 percent wind integration and increased to 11 percent of generated energy at 35 percent wind integration.

The study examined the addition of energy storage as a sensitivity. The study assumed storage capacity equal to 1 percent of peak load, 10 hours of capacity and 70 percent roundtrip efficiency. The storage units were dispatched using an arbitrage algorithm. A modest reduction in wind curtailment at 20 percent integration was observed, and the study concluded that increasing the flexibility of hydro generation would be a better solution to reduce wind curtailment than energy storage.

## 4.2 USA-based studies

### 4.2.1 Accommodating High Levels of Variable Generation — North American Electric Reliability Corporation (NERC) — 2009

Reliably integrating high levels of variable resources requires significant changes to traditional methods used for system planning and operation. This report builds on earlier experience and recommends enhanced practices and coordination efforts. Variable resources differ from conventional sources in that their fuel source cannot be controlled or stored. Fuel availability for variable resources often does not positively correlate with electricity demand, either by time of availability or geographic location.

Steep ramps can characterise the output of variable resources, as opposed to the gradual ramps of conventional generation or load. Ramp management can be challenging for system operators, particularly if down ramps occur as demand increases and vice versa. Insufficient ramping or dispatchable capability on the remainder of the grid can make these difficulties more challenging. The report makes several recommendations that show significant promise in managing VG characteristics:

- deploy different types of variable resources, such as solar and wind generation, to take advantage of complementary patterns of production;
- locate variable resources across a large geographical region; and
- design advanced control technology to address ramping, supply surplus conditions, and voltage control.

Flexible resources, such as demand response, plug-in hybrid electric vehicles, and storage capacity, may help balance the steep ramps associated with VG. Other measures to improve integration include enhanced measurement and forecasting of VG output, more comprehensive planning approaches from the distribution system through to the bulk power system, and access to larger pools of available generation and demand.

Per the report, the electric industry is on the brink of one of the most dynamic periods in its history. Ongoing efforts have the potential to fundamentally change the way the system is planned, operated, and used. Maintaining the reliability of the bulk power system during this transition will be a critical measure of success for these efforts.

### 4.2.2 The Role of Energy Storage with Renewable Energy Generation — National Renewable Energy Laboratory — 2010

Energy storage is one of the key technologies used to increase the grid flexibility and enable greater use of VG. This paper refers to other integration studies of wind to about 20 percent on an energy basis and finds that the grid can accommodate a substantial increase in VG without the need for energy storage. However, changes in operational practices are required. Thirty percent of VG integration is feasible with the introduction of low-cost flexibility options, such as greater use of demand response. The other studies did not review energy storage.

Electric vehicles are a potential source of energy for VG applications. Charging electric vehicles can be controlled and provide dispatchable demand and demand response.

Technical and economic limits for integrating VG without requiring technologies such as energy storage are based on two factors:

- the coincidence of variable supply and system demand, and
- the ability to reduce output from conventional generators.

Extreme levels of VG can cause significant curtailment of the variable generator. The decision is truly about how much VG can be installed prior to storage being the most economic option for further VG. The paper concludes that high integration of VG increases the need for all flexibility options, including storage.

Storage has been difficult to sell into the market because of high costs. However, with the reduction in cost there is more opportunity. The valuation of the services that energy storage provides and the quantification of the value of those services is a significant barrier.

In 2004, Electric Power Research Institute (EPRI) proposed several renewable-specific applications for storage and compared them with the efficiency of using storage as a grid application. By aggregating the entire net load of a system and all variable generator supply, storage or other options can be deployed at the lowest cost and greatest efficiency. However, there is a benefit for co-location when there are savings on substation and other balance-of-plant requirements.

The paper divides energy storage applications into three classes based on discharge timeframe:

- power quality, transient stability, and frequency regulation where the timeframe for discharge is from seconds to minutes;
- bridging power, contingency reserves, and ramping is from minutes to approximately one hour; and
- energy management, load leveling, firm capacity, and transmission and distribution deferral, where the discharge time is multiple hours.

Curtailing VG is a function of the fraction of system energy supplied from VG and the flexibility of the grid. VG may result in unacceptably high costs at high integration levels. Energy storage can reduce VG curtailment by shifting otherwise unusable generation and increase system flexibility by providing reserves and replacing “must run” capacity. Storage is an economic issue, based on the value of storage compared to alternatives that can complete similar functions.

The learnings for Alberta are that high levels of VG integration into the grid requires many enablers for ensuring a flexible grid, otherwise significant curtailment of VG may be required. Energy storage can be one of these enablers; however, the economics will drive the resolution on the deployment of energy storage.

### 4.2.3 Integrating Variable Renewable Energy: Challenges and Solutions — National Renewable Energy Laboratory — 2013

The National Renewable Energy Laboratory (NREL) 2013 technical report NREL/TP-6A20-60451 leverages the NREL 2010 document but provides additional insights into VG integration challenges and solutions. Variation in solar energy output during a day and over a year is highly predictable.

As the number of PV plants increases, their normalized aggregate output becomes smoother. Wind power is less predictable than aggregated solar.

Additional wind and solar power on electric grids can cause coal- or natural-gas-fired plants to turn on and off more frequently to accommodate VG. This can result in increased wear and tear and decrease efficiency. Cycling costs vary by each generator type; however, coal-fired thermal units have the highest cycling costs. Impacts on coal plants can include increased thermal stress, decreased efficiency, and increased fuel use.

The study also summarizes the Western Wind and Solar Integration Study Phase II (WWSIS-2) study, indicating that cycling had a negligible impact on expected $CO_2$ emission reductions, reduced $NO_x$ emissions, and increased $SO_2$ emissions.

Multiple choices are available to address challenges with variability associated with generation from renewable energy sources. Each grid is unique, and the optimal solution must be selected to meet each grid's requirements. The best option depends on the grid's overall flexibility, which is a result of the generation mix, market structure, operational practices, and regulatory requirements. Internationally, using multiple tools and operational practices has achieved higher levels of renewable energy generation.

Energy markets provide flexibility for real-time integration and encourage investment in the right level of flexibility. It is necessary to understand the costs of the various flexibility options, including storage, demand side flexibility, operational practices, and flexible generators. Developing metrics for assessing flexibility is useful for identifying and evaluating solutions. Fast dispatch helps manage the VG because it reduces the need for regulating reserves. Flexibility of generation sources is determined by their ramp rates, output control range, response accuracy, minimum run times and off times, start-up time, cycling cost, and minimum generation levels.

Alberta's energy market does not encourage grid flexibility since its design does not pay for ramping services or fast response. The market only pays on energy delivered.

### 4.2.4 Ramping Performance Analysis of the Kahuku Wind-Energy Battery Storage System — National Renewable Energy Laboratory — 2013

The NREL 2013 technical report NREL/MP-5D00-59003 provides an understanding of the ramping performance analysis of a large-scale utility storage system that is integrated into a wind farm in a region with high integration of VG. The KWP wind farm has 12 wind turbines at 2.5 MW each. KWP selected the Xtreme Power (XP) energy battery storage system for the site, providing 15 MW and 10 MWh of storage. This was the largest wind battery system deployed in the USA at that time. KWP chose energy storage to help avoid costly transmission upgrades, as well as meet the Hawaii Electric Company (HECO) contractual requirements for ramp rates and minimize potential power fluctuations. HECO sets ramp rate requirements at 2 MW/min to 3 MW/min. The power purchase agreement includes different up ramp and down ramp requirements that vary depending on the time of day. HECO also has under- and over-frequency and voltage ride-through requirements that define no-trip zones during voltage and frequency disturbances. KWP developed the wind farm and battery design to meet the requirements. NREL based the performance metrics on ramp rate, instantaneous power fluctuations rate, and sub-minute power fluctuation rate.

The main purpose of the XP battery system is to absorb changes in wind power plant output to limit the rate of change of power delivered to the grid. KWP based these changes on the natural variability of the wind speed resource and by contingency events on the grid. In addition, KWP used the batteries to provide ramp limiting during start-ups of a wind power plant after grid outages. In addition, after a power outage event, the batteries began absorbing a portion of the wind power plant output to limit the facility ramp rate. The benefit of energy storage is the smoothing of the overall variability of wind power at different time scales.

The learning for Alberta from this study is that energy storage can help allow for distributed generation on weaker transmission grids and support high integration of VG.

### 4.2.5 The Value of Energy Storage for Grid Applications — National Renewable Energy Laboratory — 2013

This NREL 2013 technical report NREL/TP-6A20-58465 is part of a series stemming from the USA DOE Demand Response and Energy Storage Integration Study. The report uses a commercial grid simulation tool to examine the potential value of different general classes of storage devices when providing both energy and ancillary services. The paper analyses the operational value and potential market value of load shifting/arbitrage and two classes of operating reserve products: regulating reserves and spinning contingency reserves.

The study demonstrates some of the challenges for merchant storage developers, such as the inability to capture all the system benefits potentially provided by energy storage. The study does not consider the additional value of distribution-sited generation, where small energy storage devices can defer upgrades to transmission and distribution networks. NREL completed the studies using three main “classes” of energy storage devices based on the services that they can provide: energy only, reserves only (for both spinning contingency and regulation reserves), and reserves and energy.

The report concludes that providing regulation reserves has a higher value than spinning reserves, which itself has higher value than load-leveling (arbitrage) services. The reserve services also have the advantages of requiring less stored energy. Low natural gas prices in the system inherently limited the operational value of storage in the study. The economics of energy storage depend on obtaining a capacity value, even if the device provides higher-value reserve services.

The ability to obtain full value for the services provided limits economic deployment. In some markets, storage might only be valued by the system marginal energy price and not compensated for its ability to reduce thermal plant starts. This undervalues the role of energy storage and provides benefits to thermal plants that are not paying for this advantage.

The learning for Alberta is that the AESO system does not provide capacity value, nor value associated with ramping services.

### 4.2.6 Advancing and Maximizing the Value of Energy Storage Technology — California ISO — 2014

California has legislated energy storage installations of 1.3 GW by 2024. The California ISO created a roadmap to identify the requirements to support reaching the target-assigned agency responsibilities. In working with stakeholders, California identified three major challenges:

- Ability to realize full revenue potential
- Reduce interconnection and operations costs
- Increase certainty in processes and timelines

California allocated actions across the Public Utilities Commission, the Energy Commission, and the ISO. Actions included reviewing tariffs, improving connection procedures, coordinating transmission and distribution level requirements, and clarifying market participation requirements.

In 2016, California conducted workshops on Investor Owned Utility procurement plans and market pricing[28].

### 4.2.7 Energy Storage System Plan — City of Anaheim Public Utilities Department — 2014

The City of Anaheim performed a cost-benefit analysis of energy storage technologies with the aim to develop an energy storage procurement plan. The study concludes that while energy storage technologies could provide a wide range of services, the City did not recommend them at the time because:

- Energy storage technologies are not cost-competitive for the City's required services.
- Siting in the City is difficult, as there is little spare land for power facilities and the cost of land is high.
- Energy storage systems are still maturing, and improved safety is essential, especially a reduced risk of batteries catching fire.

### 4.2.8 Potential Reliability Impacts of EPA's Proposed Clean Power Plan, Initial Reliability Review — NERC — 2014

The North American Electric Reliability Council (NERC) monitors the bulk power system's reliability in North America. This paper is an initial assessment of factors in the USA EPA Clean Power Plan that may affect system reliability. The paper identifies concerns with the volume of coal generation reductions, the increase in variable renewable generation, potential constraints on

[28] www.cpuc.ca.gov/General.aspx?id=3462

natural gas pipeline infrastructure, assumptions on energy efficiency, and the time allowed to achieve the targets.

The paper concludes that ISOs and state regulators require continued and detailed assessments to monitor reliability concerns and that the EPA should consider revising the timing requirements to maintain reliability.

### 4.2.9 Grid Energy Storage — US Department of Energy — December 2013

The Grid Energy Storage report identifies that energy storage can play a significant role in meeting the challenges of improving the grid's operating capability, lowering cost, and ensuring high reliability, and deferring and reducing infrastructure investments.

The paper also indicates that energy storage can be key for emergency preparedness because of its capabilities for backup power and grid stabilization. Pursuing a clean energy future motivates storage technology developments. In 2013, The US DOE funded 11 initiatives for an obligation of US$851 million. Other agencies, such as the DOD, NASA, National Science Foundation (NSF), and EPA, have an additional 28 initiatives. The total obligations under all government agency initiatives is $1.3 billion.

Not every storage technology is suitable for every type of application; therefore, a portfolio strategy is required for energy storage.

Energy storage faces four key challenges: cost competitiveness, validated reliability and safety, equitable regulatory environment, and industry acceptance. This paper emphasizes reducing system costs through research and development for new storage concepts, materials, components, and systems, including manufacturability and standardization.

Industrial standards for grid storage are at an early stage. Industry acceptance will grow from widespread deployment.

The future for energy storage should focus on:

- unsubsidized cost-competitiveness of energy storage technologies with other technologies providing similar services,
- value and recognition for the multiple benefits provided by energy storage, and
- seamless integration with existing systems and subsystems leading to ubiquitous deployment.

The vision for energy storage includes:

- Energy storage should be a broadly deployable asset for enhancing renewable energy integration, particularly at high levels of new renewable generation.
- Energy storage should be available to industry and regulators as an effective option to resolve issues of grid resiliency and reliability.

- Energy storage should contribute to the realization of smart-grid benefits, specifically in deploying electric transportation and optimal use for demand-side assets.

The Department of Energy has put together a focused strategy for each challenge, including:

- targeted scientific investigation of fundamental materials;
- seeded technology innovation;
- research and development programs focused on degradation and failure mechanisms and mitigation;
- developing standard testing protocols;
- documenting performance of installed storage systems;
- collaborative public-private sector characterization;
- evaluating grid benefits of storage;
- exploring monetizing grid services provided by storage;
- industry and regulatory accepted standards for siting, grid integration, procurement and performance evaluation;
- collaborative, co-funded field trials and demonstration; and
- developing storage system design tools for multiple grid services.

The report summarizes all the US DOE's ongoing work to support energy storage.

### 4.2.10 The Value of Distributed Electricity Storage in Texas — The Brattle Group — 2014

This study examines the economics of grid-connected energy storage and evaluates whether new public policies are needed. The study examines energy storage benefits from three perspectives: wholesale market participants, retail customers, and society. Figure 8 below illustrates the various benefits of energy storage.

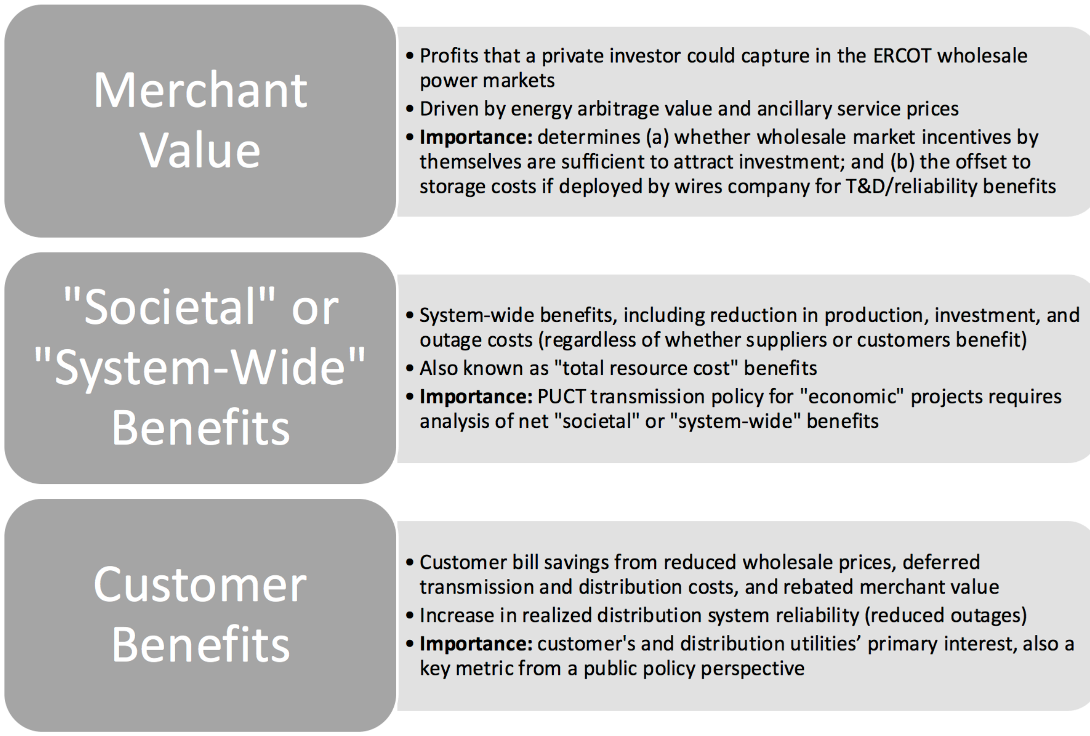


**Figure 8: Three Perspectives on Measuring the Value of Electricity Storage[29]**

The study concludes there are significant benefits for the state from deploying electricity storage when the installed cost falls to $350/kWh. The paper estimates that up to 5,000 MW/15,000 MWh of energy storage is viable in Texas. Customers would experience only a small financial benefit but would also experience improved reliability. The study finds that there is not enough value in the wholesale market alone to encourage merchant energy-storage project-development. Therefore, changes to the regulatory system are needed to enable investors to recover the full value of energy storage projects.

[29] Figure 1, The Value of Distributed Electricity Storage in Texas, The Brattle Group, 2014

# 5 ENERGY STORAGE IMPLEMENTATION BARRIERS

This section identifies technical, economic, commercial, operational, quantification and regulatory barriers to deploying energy storage in Alberta.

## 5.1 Technical

On March 15, 2016, the AESO submitted to the AUC, rule 502.13 for battery connections and 502.14 for battery operations. The rules came into effect April 26, 2016. A review of stakeholder comments during the consultation period did not elicit a strong response that any provision in the rules was restrictive or inappropriate.

The requirements for batteries are similar to the requirements for generation facilities. Requirements are included for voltage ride-through, voltage regulation, and frequency regulation. Batteries must contain ramp rate limiting controls set to a default level of 10 percent of the range between maximum charge and maximum discharge levels. Batteries co-located with generation may share reactive power requirements. Operating requirements are concerned with maintenance, reporting, and testing.

As per the AESO Storage recommendation paper, it is anticipated that CAES and pumped hydro are covered under current generator connection rules. There is no mention of treatment for flywheels or super-capacitors.

Aside from AESO requirements, technical limitations are technology-specific. CAES and pumped hydro have specific geographic requirements that limit deployment to suitable locations. Certain types of battery chemistries, such as Sodium-Sulphur, require high temperatures and need special installation and safety considerations.

## 5.2 Economic

Economic barriers to energy storage exist on both the cost and revenue side of the economic model.

There is limited public information on capital costs for many energy storage technologies. For CAES and pumped hydro, the capital cost is highly site-specific. Previously, promoted energy storage projects involving batteries relied on outside support from organisations such as CCEMC.

In late 2016, AESO is submitting an energy storage tariff to the AUC (AESO 2018 ISO Tariff Application)[30]. This tariff is consistent with the AESO recommendation paper in that storage be treated as a load when charging and generation when discharging. Under this assumption, DTS fees are significant, and project economics are severely compromised[31]. Energy storage industry

[30] https://www.aeso.ca/assets/Uploads/Posted-July-12-2016-AESO-2017-General-Tariff-Application-2016-07-07-Presentation.pdf

[31] Tables 16–19, Energy Storage — Making Intermittent Power Dispatchable, A Reynolds, Alberta Innovates — Technology Futures, 2011.

participants are interested in ensuring energy storage not be charged both DTS and STS. The outcome of the AESO Tariff application will be determined in 2017. It is unlikely that there will be large scale energy storage deployment until the AUC approves or denies the AESO tariff application for energy storage.

Natural gas prices are at historic lows and do not present a barrier for CAES installations. The corollary of low gas prices is that SCGT, the most competitive alternative to storage, is also inexpensive from an operating cost perspective.

Revenue opportunities for energy storage in Alberta are limited today. The AITF studies discussed in Sections 4.1.3 and 4.1.4 of this study identify significant revenue from energy arbitrage, however price volatility needs to be like levels observed in 2008[32]. Table 5 indicates the average spread between the highest power price and the lowest power price each day for 2007 through 2015. A higher price spread indicates higher revenue potential from arbitrage. The spread range in 2015 was about a third the 2008 level. Until price spreads recover, revenue from arbitrage alone will not be sufficient to support investment in energy storage.

### Table 5: Historical Average Daily Price Spread

| | 2007 | 2008 | 2009 | 2010 | 2012 | 2015 |
|---|---|---|---|---|---|---|
| Average Daily Price Spread ($/MWh) | $208.88 | $264.82 | $121.28 | $117.23 | $218.65 | $90.68 |

Other jurisdictions have seen energy storage used mostly for providing operating reserves. Those markets have provisions for quick-response and pay-for-performance and do not currently exist in the Alberta operating reserve market. The AITF OR analysis of revenue potential indicates that there is no ability for energy storage to capture value in the OR market under the current market structure.

The value of other services that energy storage provides do not have explicit value in the Alberta power market. The 2015 announcements of the Alberta government to introduce a capacity market provides the possibility of benefit for energy storage. The AESO has considered the creation of a ramping product[33]; however, it has not been launched currently.

Solas recommends that the AESO explore revenue opportunities for energy storage that extend beyond energy arbitrage and the current structure of the operating reserves market. One mechanism is a pay-for-performance structure in the operating reserves markets. In PJM, for example, the market is structured such that regulating reserve units that reach their dispatched volumes quicker are paid a bonus.

[32] Energy Storage – Making Intermittent Power Dispatchable, AI-TF, 2012, page 65.
[33] Phase Two Wind Integration Recommendation Paper, AESO, 2012

Further, provincial government support for researching and developing energy storage technologies could lead to the positioning of Alberta as a centre of excellence in energy storage and provide economic diversity to the province.

## 5.3 Commercial

As a deregulated marketplace, long-term contracts are difficult to achieve, and power contracts are usually in the five- to 10-year timeframe. The revenue requirements for financing need to be predictable and sufficient to ensure appropriate profitability. The reality of the Alberta market is such that the economics of arbitrage storage are difficult until sufficient margin is available.

Unless storage can be part of the operating reserves market, there is likely difficulty in obtaining finance-ability on the projects. Reducing the uncertainty of revenue and sufficient revenue is key for energy storage. The cost of energy storage needs to continue to drop to compete with the traditional generation that provides some of these services.

Lenders' knowledge of energy storage is low, and the perceived risk is likely greater than the actual risk. The lack of experience in deploying and integrating energy storage increase the perceived risk. Further deployment will overcome both barriers so that developers, investors, and financiers can gain knowledge and acceptance of the technology.

Given the interest in storage in other jurisdictions, without a large potential market in Alberta for storage, vendors may be reluctant to sell to Alberta and provide maintenance services based out of Alberta.

## 5.4 Operational

**New technical rules provide clarity.** Division 502 Technical Requirements, Section 502.14, Battery Energy Storage Facility Operating Requirements identifies the operating requirements for Battery Energy Storage Facilities. AESO issued the rule in February 2016, and the rule became effective in April 2016. These requirements apply to any operator of a battery energy storage facility connected to the Alberta grid, including facilities within the City of Medicine Hat, or behind-the-fence integration. Before the issue of the rule, the lack of technical operational requirements was a barrier to deployment. The term "battery energy storage facility" is used within the operating requirements; however, the requirements do not provide a definition.

**Large size requirements for participation in the Operating Reserve market.** The AESO is reviewing the technical requirements for providing Operating Reserve considering the attributes of energy storage technologies. Their most recent recommendation indicates that the minimum requirement of 15 MW range for regulating reserve and of 10 MW for spinning reserve should be maintained. This will limit the technologies available to operate in the operating reserves market and focus only on battery storage rather than flywheel technology.

The small market may limit ability to provide service to Alberta. A small market for energy storage in Alberta will likely be supported for maintenance from other major centres outside of Canada. In addition, Alberta's lack of personnel training on operating energy storage may require vendors to provide support services from USA-based service centres.

## 5.5 Quantification protocol barriers

Alberta has a series of seven quantification protocols that Alberta Environment and Parks (AEP) approved to quantify GHG reductions associated with displacing grid electricity with an alternative source. Alberta does not have any protocols that deal directly with energy storage.

Section 8 describes in detail several factors that impact the approach to quantifying emissions from energy storage projects. A gap analysis of the existing quantification methodologies unveils a significant barrier to determining ownership of potential emissions reduction — specifically if a transmission-integrated energy storage system provides services to multiple generators.

Without a set of policy decisions and further guidance from the regulatory authority, energy storage projects that enable emissions reductions are only offset-eligible if integrated with a renewable energy project. Section 9 further explores a comprehensive gap and recommendations for additions to existing quantification protocols.

## 5.6 Policy and regulatory barriers

There are several market and regulatory challenges to the development, implementation, and use of energy storage technology in Alberta.

### Legislative Gap

Two Acts are part of Alberta's electricity sector legislation: *Hydro and Electric Energy Act*, and the *Electric Utilities Act.* Neither of these *Acts* has any reference to energy storage. The AUC *Rule 007 Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* does not reference energy storage directly. This rule applies to applications for the construction, alteration, operation, of hydro developments, power plants, substations, transmission lines and industrial system designations pursuant to the *Hydro and Electricity Energy Act*. Applicants must choose which type of application is being made, power plant, transmission line, or distribution system. An energy storage facility that is located at generation or at load does not qualify as either transmission, distribution system or power plant descriptions.

The AESO considers energy storage to be a hybrid of both generation (when discharging) and load (when charging). This results in the AESO treating energy storage as both load and generation and held to all the rules, tariffs, standards, and process that apply to each.

### Energy market — ISO rules

The AESO recently applied for and received approval of Section 502.13 Battery Energy Storage Facility Technical Requirements and Section 502.14 Battery Energy Storage Facility Operating

Requirements. These rules are appropriate for current battery technology, and the AESO stated that other forms of storage could refer to existing technical and operating rules for generators[34].

Currently, energy market rules do not identify how energy storage participates in energy or operating reserves markets. The AESO is reviewing the market operating rules and has indicated that by 2018 that draft rules will be provided. Given Alberta's announced transition to a capacity and energy based market, these rules may be modified to incorporate energy storage.

Every minute, the last eligible electricity-block the system controller dispatched sets the System Marginal Price (SMP). At the end of the hour, the time-weighted average of the 60 one-minute SMPs is calculated and published as the pool price. As such, the price paid for electricity consumed in the hour is not known until the hour has finished.

Generators are paid the greater of the price they offer their power into the market at, or the pool price. This is designed to avoid harming a generator that generates for only a portion of the hour and offered a price higher than what the pool price settled at. Storage facilities could purchase energy in an hour and offer the energy in the same hour but at a price that ends up below their cost.

AESO Rule Section 203.1 Offers and Bids for Energy stipulates that a pool participant must submit their offer (sell) or bid (buy) before noon on the day before. It may be difficult for energy storage facility operators to know their availability or capability that far in advance. Also, depending on the market conditions, it might prove to be too expensive for them to purchase energy before the wish to provide it. Thus, they might end up sitting on the energy and storing it for 18–36 hours to ensure they have energy available for when they have offered it. This would not be economically efficient.

AESO Rule Section 203.3 Energy Restatements provides pool participants with the opportunity to restate the energy they offer into the market, but only because of an acceptable operational reason or in relation to an operational deviation. There are significant restrictions on how and when restatements can be applied, and the blocks, prices, available capability, and maximum capability must be monitored and modified as appropriate. These requirements and restrictions lead to significant compliance attention and risk. As energy storage facilities could be charging and discharging, frequently these risks, and the associated management of them can be a significant added burden to energy storage facilities.

### Ancillary services — ISO rules

Transmission Must Run Service (TMR) is generation required to be online and operating at specific levels in specific locations of the AIES to compensate for insufficient local transmission infrastructure relative to local demand. The AESO contracts with generators in areas where it requires TMR. It is

[34] Energy Storage Integration Recommendation Paper, AESO, 2015, page 6.

unlikely that storage could provide TMR, as it could only provide support for a limited period, while TMR is required for longer periods.

Generators that can restart their generation facility with no outside power source provide Black Start Services. In the event of a system-wide blackout, black start providers re-energize the transmission system and provide start-up power to generators that cannot self-start. The AESO contracts with generators in areas where it requires black start services. Most storage facilities (batteries, compressed air, and pumped hydro) do not require external support to start and would be excellent candidates for certain aspects of the AESO's black start program.

Loads that agree to be tripped following the frequency drop caused by the sudden loss of imports coming across the WECC-connected interties (the AB-B.C. intertie and Montana-Alberta Tie Line or MATL) due to intertie contingencies provide Load Shed Service for Imports (LSSi). The AESO uses LSSi to manage frequency risk so that it can increase import intertie capability, allowing additional scheduled imports to access the Alberta market without compromising system reliability. The AESO uses a competitive procurement process to contract with loads providing LSSi. It is unlikely that storage facilities could provide LSSi, as they are unlikely to charge when imports are high, likely leading to higher pool price.

The AESO has a series of ISO Rules (Section 205.1, 205.4, 205.5 and 205.6) that stipulate the technical requirements and performance standards for OR. Included in these is the minimum facility size to provide OR and the minimum amount of time that the unit must be able to consistently supply the specified amount of OR. For regulating reserve, the minimum size is 15 MW. For spinning reserve, it is 10 MW, and for supplemental reserve, it is 5 MW. These OR products also require that the providing unit can supply the contracted amount for at least one hour.

The AESO developed these minimum sizes and times in the past when large generating units provided the reserves, and they were hardly an issue for them. Storage facilities tend to be much smaller and may not be large enough to offer their services into the OR market, especially for a full hour. This is unfortunate, given that they can be excellent providers of OR services and might even be lower cost and/or more efficient than traditional suppliers[35]. Also, the ability to sell OR services might be the difference between a storage facility being profitable, and thus being developed, and not being profitable.

OR procurement at the AESO is purchased in on-peak (16 hour) or off-peak blocks (8 hour) in the day-ahead market. This is a barrier for most batteries and flywheels. Modification of this procurement practice is critical for energy storage to be part of the OR procurement.

### Tariff treatment — AESO/ Transmission/Distribution

Storage facilities can be connected at the transmission or distribution level. Distribution companies allow the smaller facilities to remain on at retail rates and just reduce their overall energy

[35] http://nparc.cisti-icist.nrc-cnrc.gc.ca/eng/view/object/?id=2d7a5190-4522-45d9-a83a-7cfe162cdb4a

consumption when they discharge back into the system. Larger storage would likely be held to rules and tariff provision like distributed generation or micro-generators, requiring that the facility owner pays for associated service upgrades, install more sophisticated metering and protection, and have the storage proponent register as a pool participant to buy and sell power at the pool price.

Storage connected to the transmission system is subject to the AESO tariff. In Alberta load pays for transmission infrastructure costs and therefore the load side of the tariff is several times more expensive than the generation side.

### Alberta Utilities Commission (AUC)

In Alberta, the AUC must approve all generation facilities and any modification to the transmission system to connect any facility (load or generation). Due to the detailed and transparent nature of the AUC application, the process can be lengthy, time-consuming, and expensive. This is the case concerning known and established forms of generation. When storage projects are introduced, which is relatively unknown in Alberta, it will likely be as long or longer until there is enough experience and a body of work that allows the AUC to feel more comfortable and advance proceedings more quickly.

Flywheel and battery storage will likely not face as much public scrutiny, as the physical facilities will not attract much attention. However, they likely will face more technical scrutiny, as the technology is new and the potential impact on the system is less certain.

Pumped hydro and compressed air storage can seem technically like existing generation (hydro and natural gas) and, thus, the AUC may be more comfortable with the technology. However, the public will likely have concerns about the potential repercussions of these technologies, as they will create certain visual and land-use impacts and may be seen to create some new and unknown risks. Proceedings with significant public concern or opposition are the longest and most expensive.

## 5.7 Summary of barriers and remedies to energy storage in Alberta

- AESO is progressing towards clearer rules for energy storage in Alberta. Connection and operation technical barriers are at least understood now that AESO rules 502.13 and 502.14 came into effect. The rules are not overly restrictive to prevent storage facilities from being connected to the AIES. Some technologies will have geographic constraints that cannot be avoided.
- Tariff is critical for energy storage economics in Alberta. AESO has prepared a tariff that considers storage as a load when charging and generation when discharging. AESO shows that with certain behaviours, the costs on the load side can be reduced by 88 percent. The tariff is certain to be subject to criticism by storage developers during the AUC approval process.

- Technological advancements reduce the costs of ESS deployment. Technological developments to reduce ESS capital costs will also enhance project profitability.
- The energy-only market creates a barrier for the financing of ESS projects in Alberta. It is not clear if or how energy storage will participate in the potential capacity market.
- The operating reserve market rules limit the types of viable energy storage. The rules make it difficult for ESS to participate in the operating reserve market. Changes to the rules are pending, but AESO has not given a timeline.
- AESO has indicated that the full range of storage dispatch, from fully charging to fully discharging, will be considered when assessing the ability to participate in the regulating reserve market. AGC signals may need to be modified to allow ESS to use the full range when providing regulating reserve.

# 6 STORAGE BENEFITS TO RENEWABLE ENERGY AND ELECTRICITY GRIDS

All electricity grids must maintain reliability to ensure the grid operates within strict limitations so that none of the grid elements/facilities are damaged and load and generation equipment connected to the grid is protected. Most noticeable to the public is maintaining grid reliability so that power continues to flow, and customers are not subject to power flicker, failures, or blackouts.

Grid reliability has been developed, managed, and maintained over the past hundred years with technology that started out simply but became more complex over time. At the same time, customers' needs have grown over time, with many commercial customers now extremely concerned about power quality and avoiding interruption due to the sensitive electronic equipment in their business.

As discussed previously, this report segregates the timeline associated with energy storage applications into those that are sub-hourly, called Power Applications, and those that are greater than one hour, called Energy Applications. See Figure 9 for representation of power applications and energy applications.

The following section details potential applications for ESS technology.

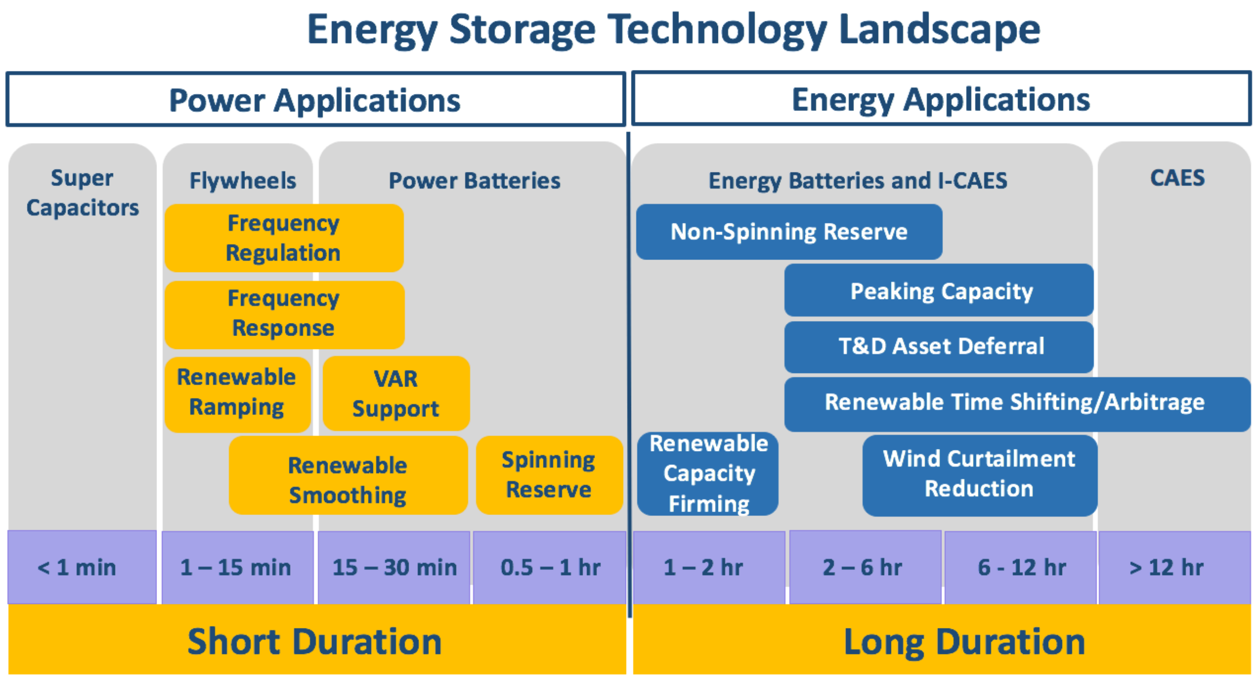


**Figure 9:** **Energy Storage Technology Landscape for Power Storage and Energy Storage Applications**[36]

## 6.1 Variable generator capacity firming

Some forms of renewable energy, such as wind and solar and some forms of hydropower, are considered variable generators (VG). VG Capacity Firming allows the variable generator to offer firm capacity on a contractual basis. This would allow the AESO to count capacity towards the AESO Supply Margin calculations. The timescale of this application is that storage must be able to discharge continuously for several hours or more. Therefore, this is an Energy application of energy storage. The applicable technologies that can be located at the variable generator to provide capacity firming are electro-chemical energy batteries and i-CAES.

Alberta's regulations do not require Renewable Capacity Firming. However, VGs have the option to bid into the energy market merit order, even without capacity firming.

Other solutions outside of storage that can provide capacity firming are simple cycle natural gas generation. If a VG does not have capacity firming, the AESO uses the energy market merit order and operating reserves to integrate the VG into the market.

[36] Adapted from NextEra presentation to AESO, 2015

## 6.2 Variable generator ramping service

Per NERC 2009, there are two major attributes of a VG that distinguish it from conventional forms of generation: variability and uncertainty.

Variability is the up-and-down production inherent to renewable energy generators such as solar and wind power. The resource variability affects the generators' output. For example, cloud cover affects the solar resource and, therefore, inherently affects electricity generation.

Uncertainty is the probability that generator output differs from a forecast. Ramping service applies to variability while regulating reserves apply to uncertainty.

VG can move in the same direction as demand change and reduce the ramping requirements from conventional generators, or it can move in opposition to demand and create operational challenges. Multiple studies have been completed that review the integration of wind and other VG. The results of these studies typically identify that integration costs are modest where wind energy or VG integration is typically less than 30 percent. The Pan Canadian Wind Integration Study reviewed the integration costs for Alberta and had a similar conclusion.

As noted in the NERC 2009 report, a key characteristic of wind power is the longer-term ramping attribute, which can greatly differ from its variability in the shorter term. There is considerable diversity in the output from wind turbines within a single wind plant, and even larger diversity among wind plants dispersed over a broader geographic region. Aggregate energy from wind power may remain relatively constant on a minute-to-minute timeframe, while output variability tends to occur gradually over an hour or more. Longer-term changes are associated with wind ramping and these specifically are a concern in Alberta.

Regions with high integration of VG with grids that have limited flexibility can benefit from storage as a reasonable option. One example is the Kahuku wind farm, (See section 4.2.4) that integrated a 30 MWh storage battery to assist with ramping due to the variability of wind.

Energy storage technologies provide ramping service by absorbing extra energy in fast up-ramping situations and supplying the energy onto the grid during fast down-ramping situations. These applications can be either power applications for sub-hourly ramps or energy applications for sustained ramp. Ramping in the opposite direction to the direction of load changes amplifies the need for the ramping service. The response time required is in minutes to hours, and the discharge time may be minutes to hours. This service's benefit is that it increases the efficiency of partially loaded thermal generators and potentially reduces both the fuel use and emissions.

Ramping service can be either co-located with generator, or provided on-grid. The NREL 2010 paper recommends providing this service on-grid so that the overall load-minus-wind ramp that occurs can be supported based on the aggregated wind, rather than any specific wind power facility.[37]

The technologies capable of providing this service on-grid include flywheels, power batteries, energy batteries, and pumped hydro. The technologies capable of providing this service in a co-located manner include power batteries and energy batteries.

Alternative technologies that can provide similar service includes simple cycle natural gas turbine generators and demand response and variable generator curtailment.

Ramping is one of the key issues that arises in the discussion of high integration of variable renewable generation. In the Phase II Wind Integration Recommendation Paper, the AESO analysed ramping and ACE events in 2011 when installed wind capacity was 777 MW[38]. The fastest total ramp up was 390 MW in 50 minutes and the fastest ramp down was 229 MW in 22 minutes. Projected to an AIES with 2,000 MW of installed wind would lead to a potential ramp up of over 1,000 MW in 50 minutes and ramp down of 590 MW in 22 minutes.

Solas analysed hourly wind output and demand using 2015 data. For the purposes of system reliability, wind can be considered as a decrease in demand. Therefore, the dispatchable generation in the EMMO must be capable of responding to changes in the value of demand minus wind.

The table below shows the maximum up and down changes in wind output, system demand, and demand minus wind for Alberta 2015 on a one- to four-hour timescale. Alberta had installed approximately 1,500 MW of wind power in 2015.

**Table 6: Maximum Hourly Changes for Wind, Demand, Demand minus Wind in 2015**

| | Wind Output | System Demand | Demand minus Wind |
|---|---|---|---|
| Up change (MW/hr) | 537 | 648 | 901 |
| Down change (MW/hr) | 481 | 493 | 887 |

Solas also assessed an estimate of ramping requirements in 2030. For this analysis, the demand was assumed to increase at 2 percent per year consistent with the AESO 2016 Long Term Outlook (LTO). Wind generation was extended by 4,200 MW to 5,663 MW with a geographic distribution consistent with the LTO. The table below shows the wind, demand, and demand minus wind hour-to-hour changes for the predicted 2030 scenario.

[37] P. Denholm et al, 2010, NREL, The Role of Energy Storage with Renewable Electricity Generation, Page 37
[38] Phase Two Wind Integration — Recommendation Paper, AESO, 2012.

**Table 7: Maximum Hourly Changes for Wind, Demand, Demand minus Wind in 2030**

| | Wind Output | System Demand | Demand minus Wind |
|---|---|---|---|
| Up change (MW/hr) | 1,474 | 925 | 1,884 |
| Down change (MW/hr) | 1,410 | 775 | 1,402 |

Ramping events due to solar generation tend to occur on much shorter timescales.

The chart below illustrates actual generation for a 3-kW roof-mounted solar generation facility in Calgary for one week.

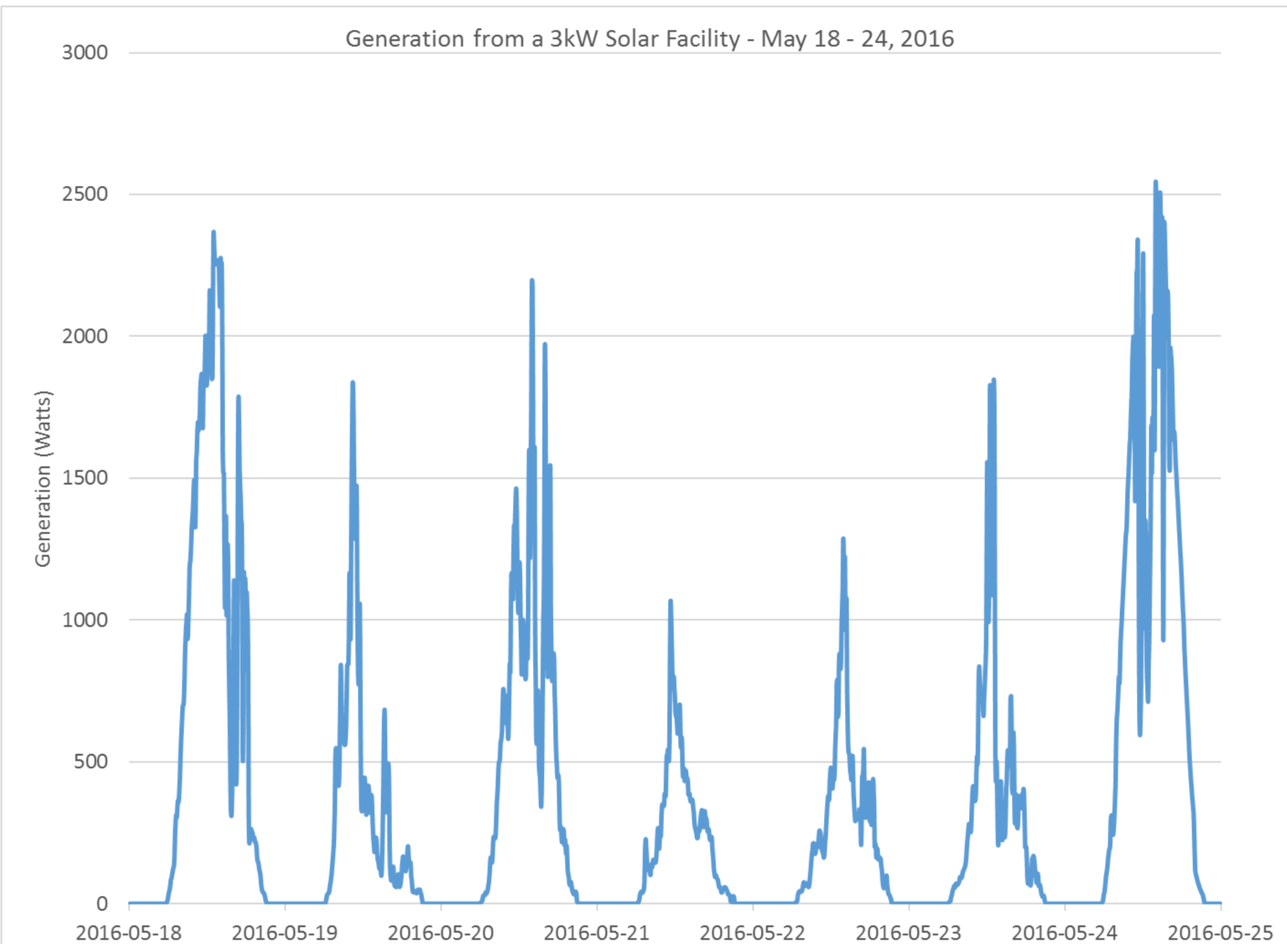


**Figure 10: Generation from a 3kW$_{DC}$ Solar Facility in Calgary**

The largest 10-minute up ramp was 1.46 kW and the largest down ramp was 1.48 kW, or almost 50 percent of installed capacity. By contrast, in 2011, the largest wind ramp observed in a 10-minute period was 100 MW, or 14 percent of installed capacity. However, blending the output of many solar facilities results in a much more even generation distribution with smaller ramps at the system level.

## 6.3 Variable generation smoothing

VG smoothing reduces the sub-hourly variability in energy generation. The response time requirement is in minutes and the discharge timeframe is sub-hourly (from minutes to 30 minutes). This reduces the need for other system assets to respond to renewable variable production, including hydropower and natural gas, or other thermal generators through the EMMO or operating reserves. Smoothing is a power application of ESS and can only be supplied by co-location with generation facilities. Solar PV systems can experience variations in output of +/- 50 percent in a 30–90 second timeframe and +/- 70 percent in a five- to 10-minute timeframe due to cloud cover.

**Table 8: Location, Technology Suitability, and Timeframe for Variable Generation Smoothing**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Flywheels, Power Batteries, Energy Batteries | 1–30 minutes |
| On-grid | Not applicable | |
| Load | Not applicable | |

Other technologies that can perform VG smoothing include simple cycle generation technology.

## 6.4 Curtailment mitigation

Curtailment mitigation reduces the curtailment of renewable energy generation during periods of supply surplus (economic curtailment), transmission constraint (physical curtailment), or extreme sustained ramping events. The required response time is from minutes to hours, and a discharge time of hours. The key benefit of this is that surplus renewable energy is used when it is needed rather than being lost due to curtailment. This allows for a larger volume of VG than the wind farm would otherwise produce. ESS is the only technology that can provide this service under supply surplus situations. The only other alternative under physical curtailment could be transmission upgrades, which have long development time requirements. SCGT could mitigate curtailment due to extreme sustained ramping events.

The technologies capable of providing this service at a generator location or at a load location are energy batteries and i-CAES. A storage facility at a generator location behind the point of interconnection can mitigate physical curtailment due to transmission constraints.

Transmission-connected CAES and pumped hydro facilities can provide curtailment mitigation for supply surplus events and extreme sustained ramping situations.

In 2015, Alberta power pool had three hours when the pool price was $0/MWh, indicating a supply surplus situation. The AESO expects the frequency of supply surplus situations may increase as renewable integration increases[39].

Physical curtailment is significant in Alberta and expected to continue in the long-term, particularly with the addition of more renewable energy.[40] [41]

In Alberta, physical curtailment is completed under a remedial action scheme (RAS). RAS occurs when the transmission system cannot handle the full output from a generator until system enhancements are complete. When this congestion cannot be handled through real-time operator action, RAS may be employed to facilitate market participation while maintaining system reliability and protecting system facilities. The AESO may assign a RAS to market participants seeking to interconnect to the system on a temporary basis prior to system reinforcements. The AESO may identify RAS requirements in the planning stage of system development or when it undertakes system studies.

The AESO may also use RAS as a permanent non-wires solution to address issues that arise on a regional or system-wide basis. System RAS is a distinct and separate concept from interconnection RAS and has its own set of business practices[42]. As of November 2016, 2,522 MW of wind power and 16 projects have applied to be connected in these regions that are currently experiencing RAS. This represents one-third of wind power capacity that have applied to the AESO are in regions that are transmission constrained. The regions with RAS (and AESO Project List wind farm capacity and number) are as follows:

- Area 42 — Hanna (1,902 MW Wind Power, 10 projects in the AESO project list November 2016)
- Area 36 — Alliance Battle River (150 MW Wind Power, one project in the AESO project list November 2016)
- Area 56 — Vegreville (no Wind Power projects in the AESO project list November 2016)
- Area 32 — Wainwright (300 MW Wind Power, one project in the AESO project list November 2016)
- Area 13 — Lloydminster (120 MW Wind Power, one project in the AESO project list November 2016)
- Area 28 — Cold Lake (100 MW Wind Power, one project in the AESO project list November 2016)

[39] Supply Surplus Discussion Paper, AESO, 2010, page 3.
[40] 2016 Pan-Canadian Wind Integration Study, GE Canada, Section 01, Summary Report, Page 26
[41] 2016, Annual Report on Costs Incurred as a Result of Mitigating Transmission Constraints, AESO, Page 4
[42] www.aeso.ca/downloads/RAS_Guideline_Discussion_Paper_July_03_2009.pdf

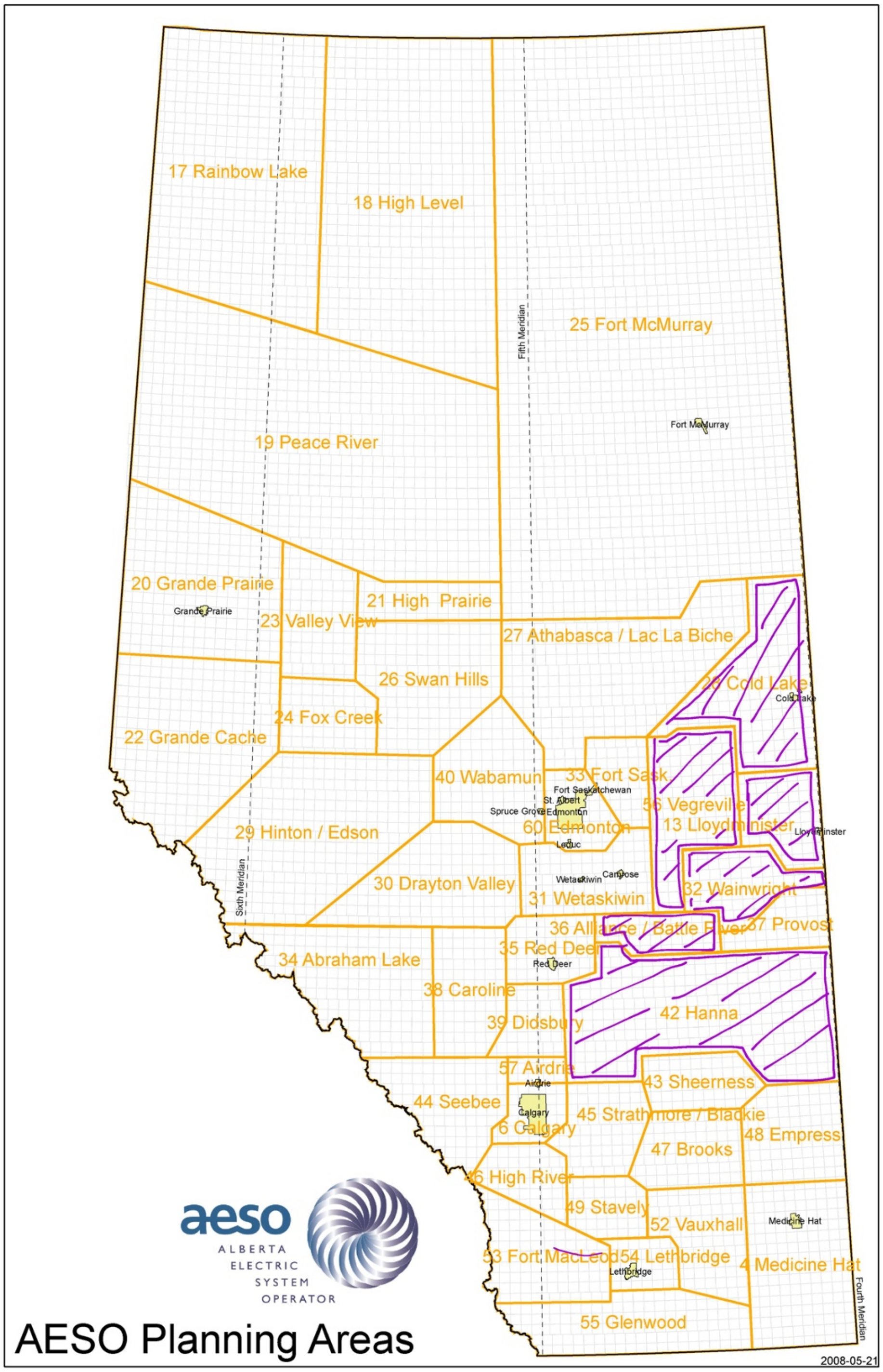


**Figure 11:** **AESO Planning Areas with RAS as of May 2016**

The Area 53 Fort Macleod had a long-term RAS in place. This affected the production of multiple wind farms in the regions to as much as 25 percent of production loss in some seasons. The AESO alleviated this issue with additional transmission build; however, the RAS was in place for over eight years.

## 6.5 Time-shifting/Arbitrage

Time-shifting or arbitrage is an ESS application by purchasing low-cost, off-peak energy and selling or using it during periods of high prices. Time-shifting ESS solutions can be located at the customer site, generator site, or connected to the transmission grid.

The timeframe for time-shifting is from minutes to hours, and the discharge time is in multi hours. The benefits are that it increases the use of baseload power plants and decreases the use of peaking plants. This can lower the system fuel costs and potentially reduce emissions if peaking units have lower efficiency than baseload units.

Solas' analysis indicates that time-shifting or arbitrage in Alberta is best when utilizing an ESS with between 2-12 hours of energy capacity.[43] This represents the time difference between when ESS charges during low price periods and discharges during high price periods. Solas' analysis indicates that daily price volatility is greater than seasonal volatility. Therefore, ESS does not need to store in winter and discharge in summer months. The applicable technologies for this timeframe include the following (see Table 9).

**Table 9: Location, Technology Suitability, and Timeframe for Time-shifting/Arbitrage**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Energy batteries and i-CAES | 1–12 hours |
| On-grid | Energy batteries and i-CAES, CAES and pumped hydro | 1–12 hours |
| Load | Energy batteries and i-CAES | 1–8 hours |

BC based energy traders have the capacity to purchase electricity from Alberta complete arbitrage, store the power in their hydro facilities, and sell the power back to Alberta during high price times. Within Alberta, Solas is unaware of any known technology facilities designed for time-shifting or arbitrage.

Developers have proposed several ESS projects for arbitrage purposes. Arbitrage economics depend on price volatility. In 2015, price volatility in Alberta was lower than other years due to surplus generation connected to the AIES. Looking forward, volatility is expected to increase due

[43] Diurnal pricing profile demonstrates peak pricing at HE 17-23 (Nov-Jan) and HE 18-23 all other months. Off peak includes HE 1-7 and HE 24 - AESO Training Program, November 2016.

to reduced coal capacity and the increase in VG. The exact amount of volatility seen in the market depends on demand growth and the volume of natural gas capacity added as coal power generation is retired.

As an illustration, Solas examined the impact ESS would have had on price volatility in Alberta in 2015.

It was assumed that 150 MW of storage capacity was installed, to match 10 percent of installed wind capacity. The storage facility was assumed to charge during the hours when prices were in the lowest third of the distribution and discharge when prices were in the highest third. An adjusted price was calculated by moving up or down the EMMO by the charging or discharging volume.

For this analysis, volatility is the standard deviation of the hour-to-hour price changes. Adding storage reduced price volatility by 17 percent. ESS when used for arbitrage will mitigate concerns of increased price volatility due to renewable expansion.

## 6.6 Peaking capacity

Peaking capacity provides reliable capacity to meet peak system demands. Charging occurs at non-peak hours. The ESS facility must be able to discharge continuously for several hours or more. This provides the ability to replace or function as a peaking generator. The ESS can be located at the generator or on-grid for peaking capacity. The technologies that can support this service include energy batteries and i-CAES.

**Table 10: Location, Technology Suitability, and Timeframe for Peaking Capacity**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Energy batteries and i-CAES | 1–12 hours |
| On-grid | Energy batteries, i-CAES, CAES, pumped hydro | 1–12 hours |
| Load | Not applicable | |

In Alberta, the alternative solution to using ESS is simple-cycle natural gas generation, demand response, and hydropower.

## 6.7 VAR support

Voltage and Reactive Reliability Standards ensure voltage levels and controls and reactive flows and resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the interconnection. ESS can provide VAR support and contribute to system reliability in the Voltage and Reactive category of AESO reliability standards.

In Alberta, there is no market for VAR support, but all generation types, including wind, battery, and solar, are expected to contribute to reactive power requirements. AESO technical rule 502.1

for wind integration and the AESO technical rule 503.14 for battery operations identifies this requirement. The AESO will likely require this in the solar rule it is developing. In other jurisdictions, ESS can provide VAR support.

## 6.8 Frequency regulation and response (known as regulating reserve in Alberta)

The electric grid requires a constant frequency to be maintained, which the AESO maintains. The AESO provides services in short, several-second adjustments either to increase or decrease the system frequency. In Alberta, the response time is up to one hour under the regulations. These regulations are for both frequency response and maintain the ACE. Frequency could be a perfect 60 Hz; however, the AESO may be 100 MW off the schedule. Every four seconds, the AESO calculates a new regulatory set point and sends it to each provider. The AESO considers the application of frequency response a power application for ESS.

**Table 11: Location, Technology Suitability, and Timeframe for Peaking Capacity**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Flywheels, power batteries, energy Batteries, i-CAES | 1–30 minutes |
| On-grid | Flywheel, power batteries, energy batteries, i-CAES, CAES, pumped hydro | 1–30 minutes |
| Load | Flywheel, power batteries, energy batteries, i-CAES, CAES, pumped hydro | 1–30 minutes |

In Alberta, the alternative solution to using ESS for this application is hydropower, coal power, cogeneration, and combined cycle natural gas generators. ESS has fast response time for frequency response; flywheels are highly effective for frequency response.

The performance of thermal power generators at following automatic generator control (AGC) signal varies by type of power. In a study completed by NRC, *Regulating Reserve Performance Assessment* for the Alberta Electric System Operator (A. Grewal) 2016 found that natural gas had an averaged regulation performance of 75.3 percent and coal 67.4 percent compared to hydro power at 85.6 percent. The study indicated that "improvements in overall AIES fleet performance could be realized by incorporating fast-acting assets, but that further study is required to fully assess the optimal mix of regulation assets." ESS can have a much higher averaged regulation performance particularly compared to thermal power generation. The value of using ESS for regulating reserve is that this reduces the financial cost associated with the volume of regulating reserves procured. This reduces the overall costs to consumers for electricity.

The study indicated that the measured performance of the conventional assets was found to correlate with their relative ramp rates. The study also indicates that "Since it is widely expected that the growth of VG will continue, a corresponding need for more efficient regulating reserve to maintain system reliability and performance is also expected. While there is clearly a role for fast-acting assets to positively impact system performance, further study and results aggregation from markets already dispatching fast-acting assets is required to inform a specific policy reform or change to market rules."

ESS facilities that provide frequency regulation and response contribute to system reliability in the Resource and Demand Balancing category.

## 6.9 Spinning reserves

Spinning reserves are fast-responding increases or decreases in generation or load to random, unpredictable variations in demand or generation or intertie activity. The response time required is in minutes. Spinning reserve is needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings. In Alberta, the discharge time for spinning reserves is up to one hour. The use of ESS for this service reduces the use of partially loaded thermal generators, potentially reducing both fuel use and emissions.

**Table 12: Location, Technology Suitability, and Timeframe for Spinning Reserves**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Flywheels, power batteries, energy batteries, i-CAES | 1 to ~30 minutes |
| On-grid | Flywheel, power batteries, energy batteries, i-CAES, CAES, pumped hydro | 1 to ~30 minutes |
| Load | Flywheel, power batteries, energy batteries, i-CAES, CAES, pumped hydro | 1 to ~30 minutes |

Other technologies that provide this service include hydropower, coal power, and combined cycle natural gas technology. ESS facilities that provide spinning reserve contribute to system reliability in the Resource and Demand Balancing category.

## 6.10 Non-spinning reserves (supplementary reserves)

Non-spinning reserves are off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO and can maintain that output for at least two hours. Non-spinning reserve maintains system frequency stability during emergency conditions. In Alberta, dispatch response time requirements are 15 minutes. Discharge time is up to one hour. The AESO considers non-spinning reserves a lower-value service.

**Table 13: Location, Technology Suitability, and Timeframe for Non-Spinning Reserves**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Power batteries, energy batteries, i-CAES | 15–60 minutes |
| On-grid | Power batteries, energy batteries, i-CAES, CAES, pumped hydro | 15–60 minutes |

| Location | Technology Type | Timeframe |
|---|---|---|
| Load | Power batteries, energy batteries, i-CAES | 15–60 minutes |

Other technologies that can provide non-spinning reserves include hydropower, simple cycle natural gas power generation, combined cycle natural gas power generation, and demand response.

ESS facilities that provide non-spinning reserve contribute to system reliability in the Resource and Demand Balancing category.

## 6.11 Transmission and Distribution Asset Deferral

Transmission and Distribution (T&D) Asset Deferral reduces loading on the T&D system during peak times. The response time required is in minutes to hours, and the discharge time required is in hours. T&D asset deferral provides an alternative to new transmission lines and substations that could be expensive and difficult to site. The existing markets do not capture the value of T&D deferral.

**Table 14: Location, Technology Suitability, and Timeframe for Transmission and Distribution Asset Deferral**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Not applicable | |
| On-grid | Energy batteries, i-CAES, CAES, pumped hydro | 2–12 hours |
| Load | Not applicable | |

In Alberta, many regions require transmission and distribution upgrades to allow for distributed generation. The AESO, as part of the *Transmission Regulations*, cannot seek any solution for congestion besides additional transmission or distribution deployment. The AESO is of the view that "current legislation does not support a storage unit which provides energy or ancillary services to also be part of the rate regulated transmission system. Generating units are specifically excluded from the Electric Utilities Act (EUA) definition of transmission facility."[44]

ESS facilities that provide T&D Asset Deferral contribute to system reliability in the Transmission Operations and Transmission Planning categories.

## 6.12 Peak shaving

Peak shaving is used for load to reduce purchases from the grid at time of high internal demands. The response time required is in minutes to hours and the discharge time required is hours. This

[44] AESO, Energy Storage Integration Recommendation Paper, June 2015

increases the use of baseload power plants and decreases the use of peaking plants. This can lower demand charges for load customers.

**Table 15: Location, Technology Suitability, and Timeframe for Peak Shaving**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Not applicable | |
| On-grid | Not applicable | |
| Load | Flywheels, power batteries, energy Batteries, and i-CAES | From 15 minutes to eight hours |

The only solution that can provide peak shaving, other than ESS, is demand response. Demand response, also called load-shedding service, occurs when customers change their load behaviour to reduce their load. In Alberta, peak load determines a significant number of Demand Transmission Service (DTS) charges.

## 6.13 Uninterruptible Power Supply (UPS)

UPS provides an instantaneous response, where discharge time depends on the level of reliability needed by the customer. ESS is located on site with the customer and can be an energy- or power-based application. ESS provides an alternative to on-site diesel power generation.

**Table 16: Location, Technology Suitability, and Timeframe for UPS**

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Not applicable | |
| On-grid | Not applicable | |
| Load | Flywheels, power batteries, energy batteries, and i-CAES | Instantaneous to 30 minutes |

The only non-ESS solution available for UPS is diesel power generation.

ESS facilities that provide UPS contribute to system reliability in the Critical Infrastructure Protection, Emergency Preparedness and Operations and Facilities Design, Connection and Maintenance categories.

## 6.14 Power quality

ESS can support issues such as voltage spikes, sags, momentary outages, and harmonics. Typically, this is used at the customer load sites to buffer sensitive equipment. The response time is less than one second and the dispatch time is less than 15 minutes. This provides an alternative to load loss, and equipment loss at customer sites.

### Table 17: Location, technology suitability, and timeframe for UPS

| Location | Technology Type | Timeframe |
|---|---|---|
| Generation | Not applicable | |
| On-grid | Not applicable | |
| Load | Flywheels and power batteries | Instantaneous to less than 15 minutes |

There are no other solutions available except ESS. ESS facilities that provide power quality services contribute to system reliability in the Critical Infrastructure Protection category.

# 7 STORAGE AND RENEWABLE ENERGY

## 7.1 Current levels of renewable energy integration

Alberta's renewable energy deployment is 8 percent of the energy market (wind, solar, hydro, biomass). The variable generators (wind and solar) of this market make up 5 percent of the energy market in 2015. Most of the variable generators are wind power at over 1,400 $MW_{AC}$, since only 9 $MW_{DC}$ of the market is made up of solar power.[45] As of November 2016, Alberta's solar deployment is 13 $MW_{DC.}$

In Alberta, levels of renewable energy integration are low compared to other jurisdictions (see Figure 14). East Germany, Denmark, Spain, India and Texas all have a considerably higher level of renewable energy integration. As indicated previously, Alberta has a significant resource of solar, wind, biomass, and some applications for geothermal and hydropower.

Figure 12 demonstrates how the electricity grid integrates coal power, natural gas, and renewable energy, including VG. The four charts show the seasons and the impact of wind production compared to the thermal power generators.

These charts demonstrate that coal is the significant contributor to the energy market, followed by cogeneration, combined cycle, simple cycle, and then wind energy, hydropower, and other (mostly biomass). The charts demonstrate the natural cycle of load in the rise and fall of demand. The charts include at least one weekend day and show clearly a lower demand on the weekend. This snapshot is taken over four days (96 hours).

The February 2015 chart demonstrates how coal and cogeneration dominate the production. Coal can ramp up and down to meet load; however, cogeneration remains constant. In this chart, CCGT does not have significant production, and SCGT is minimally used. Wind power generates more energy than CCGT and SCGT combined. Wind power production is relatively constant and does not have significant variability during this timeframe.

The spring season (May 2015) shows lower coal power generation and a significant number of ramp up and downs. Coal production may have been reduced due to outages. Some of the coal ramp ups are in the opposite direction to load. Cogeneration production is significantly less than the February production. CCGT has increased significantly and appears to be able to ramp down as required when demand drops. SCGT is seen in times of higher load, during the daytime peak. Hydropower production has higher production levels than wintertime. Wind power generation during this timeframe has lower production than wintertime; however, it remains relatively constant. SCGT clearly demonstrates that it handles most of the swings.

45 Solar deployment from G. Howell, Mayhew Howell Engineering, Wind, hydro, biomass statistics from 2015 Annual market statistics data file - AESO.

The summer season (July 2015) shows a higher daytime peak load and continues to show coal power ramping up and down with more volatility than the winter (February 2016) production. Cogeneration is lower production in the summer months, and CCGT production is higher than the winter. SCGT production is not present in these four days. Hydropower has a larger presence during this time and wind power has lower production than winter.

The fall season demonstrates higher coal power generation and day and night ramping capabilities. Cogeneration has increased production closer to winter production levels. CCGT production has reduced compared to summer and spring production. Hydropower has reduced compared to spring and summer. Wind power has increased. There is little to no SCGT during this timeframe, and coal power manages the swings in load, and CCGT manages swings in wind power production. Cogeneration demonstrates little flexibility.

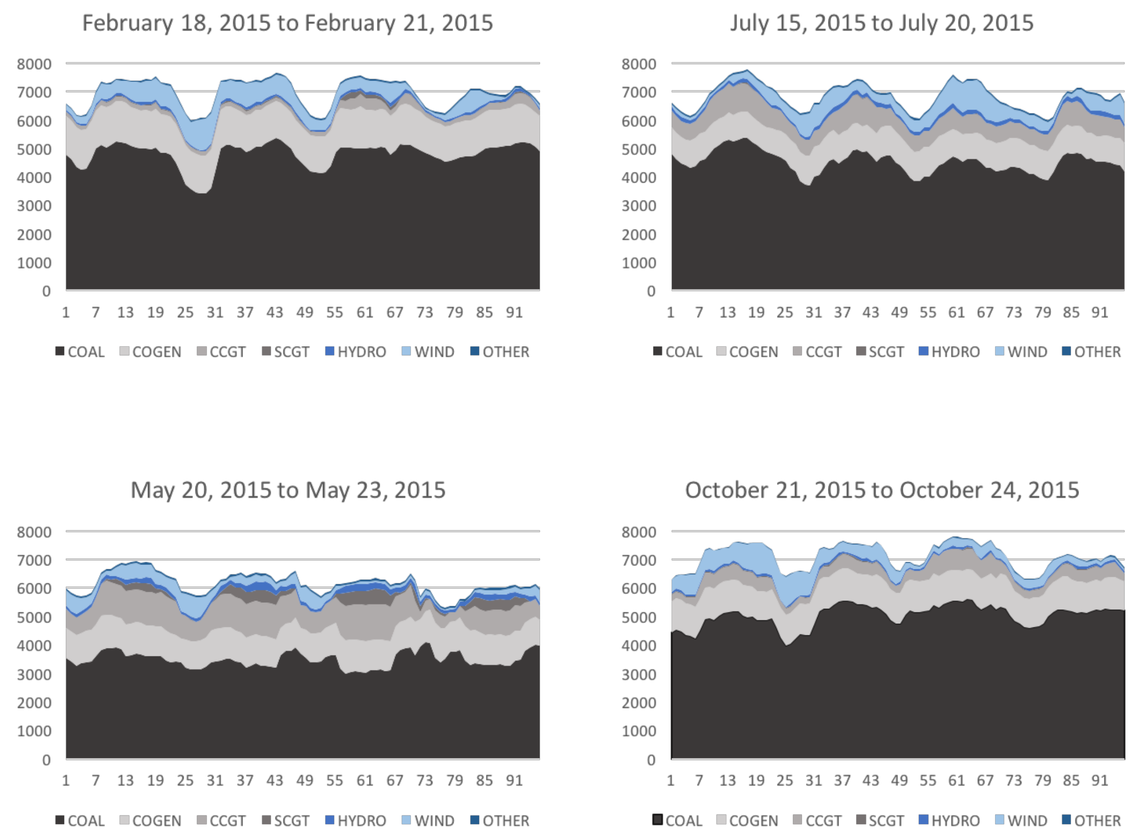


**Figure 12: Production by Generation Type at Each Season in 2015 — Alberta-based Production (MW) by Time (Hour)**

## 7.2 Predicted levels of renewable energy integration — AESO predictions

Six Alberta based studies have been completed since 2012 that deal with renewable energy integration. These are publicly available to identify how much integration could be completed in Alberta. These include the AESO Long Term Outlook (2014), The Brattle Policy Study (2014), Pembina's Power to Change (2014), AESO Phase 2 Integration (2012), CanWEA Wind Vision (2013), and the IPPSA study (2013)[46]. Figure 13 below demonstrates these scenarios.

[46] Policy Options and Considerations for Reducing Greenhouse Gas Emissions and Encouraging Renewable Generation Development in Alberta, The Brattle Group, November 2014
Trends in GHG Emissions in the Alberta Electricity Market — Impact of fuel switching to natural gas, EDC Associates Ltd., May 2013
AESO 2014 Long-term Outlook, Alberta Electric System Operator, 2014
Phase Two Wind Integration — Recommendation Paper, AESO, December 2012

Each of these studies reviews the integration of renewable energy in the Alberta electricity market. The studies can be categorized into three different scenarios: high, medium, and low. The low scenario looks at approximately 4,000 MW of wind and hydro capacity, or around 14 percent of energy by 2035. The medium scenarios included approximately 6,000–8,000 MW of wind and hydro capacity and around 19–29 percent of energy. Brattle completed the high case, and Pembina's Power to Change included approximately 11,000 to 13,000 MW of new wind power and hydropower capacity and around 32–41 percent of energy by 2035. In these cases, the assessment indicated that the energy market is viable even with large volumes of VG.

The Alberta government plan for renewable energy is consistent with the high scenario in Figure 13; however, it is expected to be achieved by 2030 rather than 2035. Neither the Brattle Group report nor the Power to Change report indicated any concerns about integrating this level of renewable energy.

The Brattle Group report identified high levels of renewable energy integration but did not provide significant discussion on the ramifications. The supply scenarios were done for transmission planning purposes and intended to reflect the range of possible development paths. Their recommendations were focused purely on market design and coal retirement policies. The Power to Change Report also had limited discussion of the potential ramifications of high levels of renewable energy integration.

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Power to Change — How Alberta can green its grid and embrace clean energy, Pembina Institute and Clean Energy Canada, May 2014

Alberta WindVision Technical Overview Report, Solas Energy Consulting, May 2013

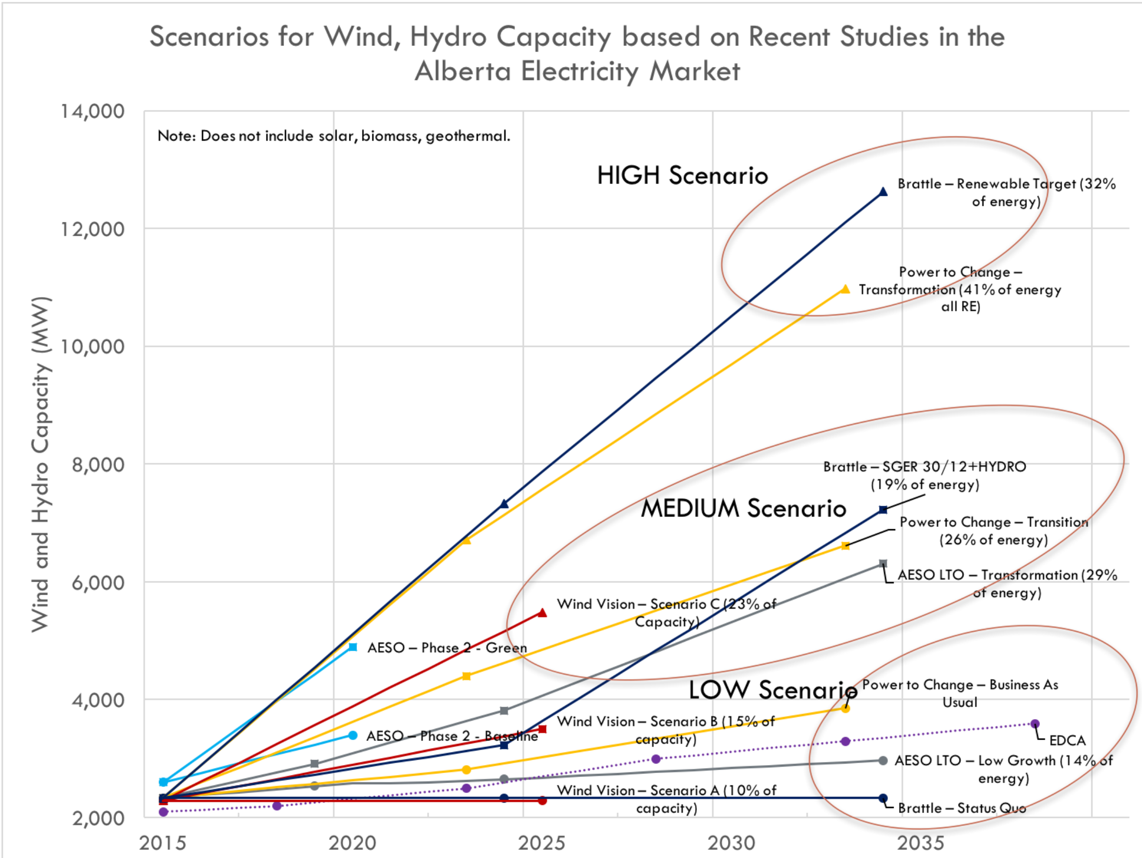


**Figure 13: Scenarios for Wind, Hydro Capacity Based on the Most Recent Studies for Renewable Energy Integration in Alberta**

GE completed another study, which involved the AESO, called the Pan Canadian Wind Integration Study (not included in the figure above). This study noted that wind plants do not require dedicated backup. The study identifies that for each additional 1,000 MW of wind power added in Alberta, only 25 MW of regulating reserves are required. [47] Another way to say this is that the increased regulation reserve as a percentage of capacity for Alberta is 2.5 percent. The GE Pan-Canadian Wind Integration Study has been released and is located on the CanWEA website.

The integration level of VG has been increasing over the past few years. Islanded grids can achieve levels as high as 50 percent variable renewable energy integration and are targeting 70-80 percent renewable energy by 2020-2023 for some locations.[48] Mainland renewable energy integration levels are pushing as high as 42 percent by capacity. The ability to integrate into grids

[47] Sneak Peak: Pan Canadian Wind Integration Study (PCWIS), Tom Levy, Natural Resources Canada, 2016
[48] Islanded Grid Wind Power Conference – March 2015, High Contribution Wind, Rich Stromberg, Alaska Energy Authority

highly depends on the grid's flexibility. Alberta's target of 30 percent integration is not insurmountable based on what other jurisdictions have achieved.

Figure 14 shows the integration levels in many jurisdictions. As noted in the chart, the boundary of what is possible expands. Alberta has only approximately 8.8 percent wind generation integration by capacity. Alberta can learn from other jurisdictions that have higher integration levels. These jurisdictions are shown below.

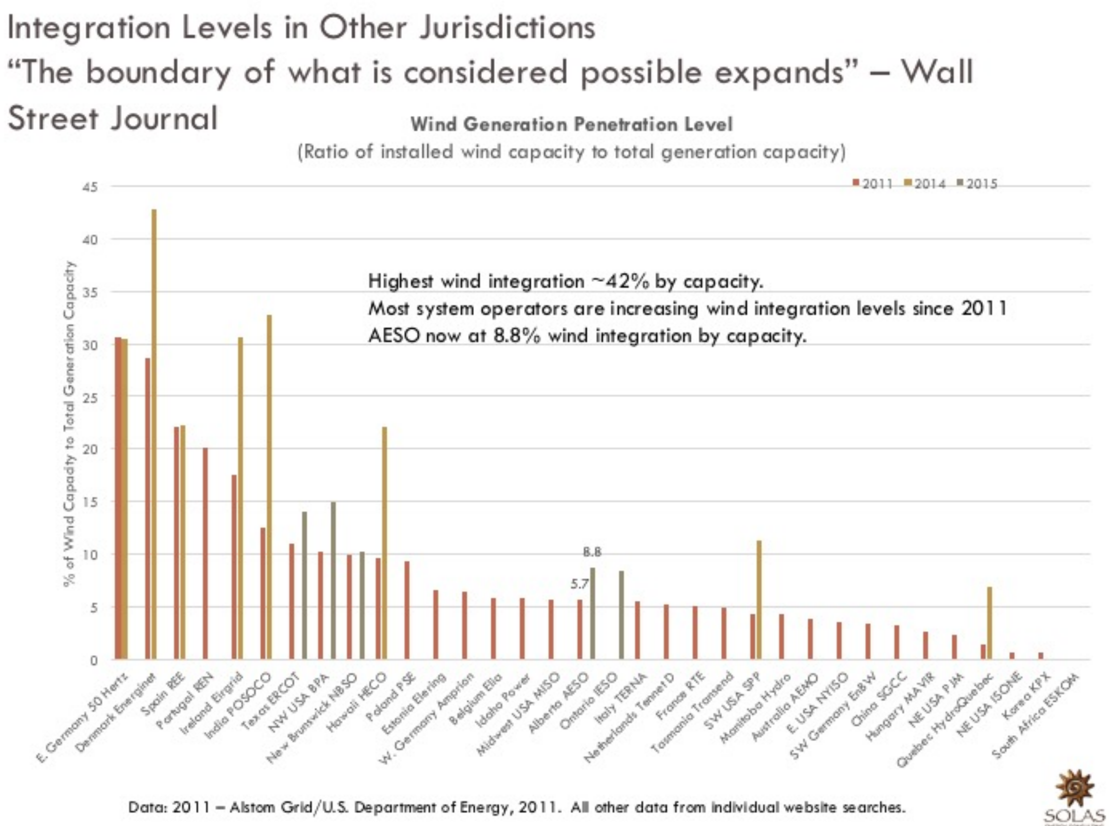


**Figure 14: Integration Levels of Wind Power in Select Countries.**

## 7.3 A review of potential issues that may be encountered by renewable energy in Alberta

In Alberta, under the current market regime, most of the issues with renewable energy deployment are due to the economic market and transmission constraints. The following lists the potential and current issues that may be encountered by renewable energy in Alberta.

- Economics of renewable energy under the energy only market design and power pricing

- Policy certainty. Alberta has potential risk of policy reversal should a new government come into effect.
- Capture rate wind ghettos – Under the energy only market design, geographic concentration of wind power results in lower revenues for wind farms that are highly correlated with production profiles.
- Significant curtailment at high levels of renewable energy integration rates due to transmission congestion, supply surplus and extreme sustained ramping events.
    - RAS[49], have been utilized to reduce generation when specific protection schemes are implemented. This reduces the economics of wind power. Achieving Alberta's target of up to 30 percent of energy from renewable energy will likely encounter RAS, trigger additional transmission build, and require additional ramping flexibility.
    - Supply Surplus – During periods when more baseload supply is available than demand, (typically at night), wind power is curtailed
- Insufficient transmission access – The AESO has indicated that the current transmission build has sufficient capacity for approximately 2,900 MW-3,200 MW[50]; meeting Alberta's objective of 30 percent (5,000 MW) will require additional transmission availability. Retiring coal plants will create some additional transmission space; however, some of these locations do not have sufficient wind resource to be replaced by commercially viable wind power. The Hanna region has coal plants as well as a strong wind resource.
- Insufficient grid flexibility to enable large scale renewable energy integration. Grid flexibility can come in the form of fast response dispatchable natural gas, hydro power or interconnection to other jurisdictions. Alberta has a high integration of slow responsive coal and cogeneration facilities and limited interconnection capacity to neighbouring jurisdictions.
- Lagging regulations for integration of renewable energy (crown land policies, solar technology specifications, regulatory processes that accommodate and acknowledge renewable energy's unique attributes). Currently, Alberta has no crown land policies for renewable energy deployment. The AESO does not have technical rules for solar energy or geothermal power. The AUC Rule 007 does not mention solar energy or geothermal power as part of the application process.

[49] Remedial Action Scheme is a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include adjusting or tripping generation, tripping load, or reconfiguring a system. RAS accomplish objectives such as meeting NERC reliability standards, maintaining bulk electric system stability, maintaining acceptable bulk electric system voltages and power flows and limits the impact of cascading or extreme events. - http://www.nerc.com/FilingsOrders/ca/Canadian percent 20Filings percent 20and percent 20Orders percent 20DL/Alberta_RAS_Definition_filing.pdf

[50] Southern Alberta Transmission Reinforcement (SATR) has approximately 2400 MW capacity. The most recent Hanna upgrades have approximately 500 MW available capacity.

# 8 HOW DOES AN ENERGY STORAGE PROJECT CREATE AN EMISSION REDUCTION?

The question as to whether ESS creates emission reductions or enables emission reductions has been debated significantly in Alberta and Canada. There are multiple storage technologies, multiple applications, and three potential locations (at generator, on-grid, at load) for installation of ESS. Clearly, the answer is not simple.

This study begins to answer this question, initially using an offset-project-style focus to determine how this can be quantified. This approach will answer the question of whether an ESS project creates emission reductions. Using the results as a guide, the report then answers the question of whether ESS enables emission reductions.

Quantification of GHG emission reductions are completed with the use of a project protocol. The project protocol provides a credible and transparent approach to quantifying and reporting GHG emission reductions, enhances the credibility of the GHG project accounting by using common accounting concepts, procedures, and principles, and provides a platform for harmonizing different project-based GHG initiatives and programs.[51] Determination of the GHG assessment boundary is required to fully quantify the GHG reductions from an individual project. The GHG assessment boundary includes any primary effect (intended change) caused by the project activity, as well as any secondary effects (unintended changes).

Solas's approach utilizes international best practices, defined by the World Resources Institute, and the International Organization of Standardization (ISO). This definition of an emission reduction remains relevant regardless of the regulatory system governing the quantification of emission reductions.

ISO 14064 provides principles and requirements at the project level for quantification, monitoring and reporting activities intended to cause GHG emission reductions or removal enhancements, validation and or verification of GHG assertions. The principles behind ISO 14064 have been used in national calculation methodologies such as the Canadian National Inventory Report.

The World Resources Institute (WRI) provides *Guidelines For Quantifying GHG Reductions From Grid-Connected Electricity Projects*. This document provides information related to GHG accounting and quantification procedures, and key concepts necessary to understand and perform the GHG accounting procedures. They also provide full guidance on accounting for GHG reductions from individual grid-connected electricity projects, and examples of how these guidelines can be applied to estimate baseline emissions.

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[51] The Greenhouse Gas Protocol, Guidelines for Quantifying GHG Reducitons from Grid-Connected Electricity Projects, World Resources Institute, 2005
http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf

Most Canadian federal and provincial institutions, agencies and government programs associated with GHG quantification, validation and verification use ISO 14064 and the WRI guidelines. This approach was used in this report for GHG quantification for ESS.

An emission reduction is determined by quantifying the difference between the emissions generated in the **baseline** and the **project condition** as Equation 1 below illustrates. The baseline condition for a project is a reasonable representation of conditions likely occurred during a specified period had the project not been implemented. In other words, the baseline represents "business as usual" and the project represents a change from this practice.

The project condition is a specific action targeted at reducing or removing GHG emissions.

Section 10 further summarizes a description of the ISO *International Guidance on Quantifying Greenhouse Gas Emission Reductions from Projects.*

### Equation 1: Quantifying Emissions Reductions (General)

$$\text{Emissions Reduction} = \text{EMISSIONS}_{\text{BASELINE}} - \text{EMISSIONS}_{\text{PROJECT}}$$

Multiple factors influence what sources of emissions are quantified in determining the baseline and project conditions for electricity storage projects (see below).

### Table 18: Factors for Consideration in Quantifying Project and Baseline Emissions for ESS

| Factor | Description |
| --- | --- |
| Project boundary | The project boundary defines what emissions sources and reductions are in-scope and relevant. An ESS project can be independent of the energy source. Therefore an ESS project could provide multiple services to multiple electricity suppliers.<br>For example, multiple generators may contract a single ESS facility located along the transmission grid to provide curtailment and arbitrage services, while serving the electric system operator as a participant in the Supplemental Reserves Market. In this example, the project boundary is drawn around the storage project, regardless of location.<br>Alternatively, ESS is an integrated component of a generation system, enabling the participation of this generator in the electricity market. In this case, the project boundary is drawn around the entire integrated generation/storage project. |
| ESS technology | The storage technology's efficiency will vary. Specific storage technologies may also require energy inputs or the use of ozone-depleting substances to operate. Therefore, different technologies are associated with varying project-level emissions intensities |
| Charging or discharging | When a storage system charges, another generator in the integrated electricity system must increase generation, except for when generated electricity would be otherwise curtailed.<br>When discharging, the integrated system responds by ramping down generation elsewhere.<br>The AIES' inverse response to charging and discharging results in a scenario where charging and discharging must be viewed as separate activities, with unique baseline and project conditions for each.<br>The net emissions associated with an ESS project must be determined by taking the difference of the emissions during charging and the emissions during discharging. |
| Location of storage/Source of energy | ESS can be located (1) at the generation source at a point before the connection to the transmission/distribution system; or (2) integrated into the transmission/distribution system at a point before the connection with a load source; or (3) at a point after the connection of a load source with the transmission/distribution system. Depending on the project boundary, the relative intensity of the electricity source influences the emissions intensity (emissions per unit of electricity stored). |
| Storage capacity and discharge rate | Electricity storage technologies have varying capacities expressed as a unit of time. These technologies are grouped into their applicability, power, or energy, based on their capacity. |
| Market in which storage is participating | Known as the Operating Reserves in Alberta, services such as spinning reserve, non-spinning reserve, frequency regulation, and frequency response participate in a market that differs from the energy market and is made up of a select group of generators. Therefore, the GHG emissions intensity of the Operating Reserves market differs from the marginal intensity of the energy market. This impacts the emissions' intensity of the baseline scenario for charging and discharging. |
| Time of day of charging/ discharging | For some services, charging and discharging strongly correlates to the time-of-day. The marginal intensity of the electricity grid varies during the time-of-day, impacting the emissions' intensity of the baseline scenario for charging and discharging. |
| Congestion relief and the transmission grid efficiency | As the energy stored relieves transmission congestion, ESS to shift current or load from the peak period to the off-peak period reduces distribution line losses. This decreases the net resistive losses, which the lower temperature of the line during off-peak hours further enhances. |

| Factor | Description |
| --- | --- |
| Time-shifting impacts on efficiency of partially loaded thermal plants | Some applications of ESS contribute to the improvement of the efficiency of thermal generators, which make up the operating margin and are only partially loaded. This is applicable when a storage technology can absorb excess energy in fast up-ramping situations and supply needed energy through fast down-ramping. |

Solas conducted a detailed analysis of the GHG reductions generated/enabled by various ESS technologies, application type and location. Section 9 describes these in detail. This analysis evaluates the potential based on the grid generation mix and associated marginal grid intensities in 2015 and the forecast intensity in 2030.

Solas determined the GHG annual emissions of each case, describing the location, technology, and storage application as follows.

### Equation 2: Quantifying Emissions Reductions for ESS Projects

$\text{ANNUAL EMISSIONS}_{\text{STORAGE}}$ (Tonnes $CO_2e$) =
($\text{ANNUAL EMISSIONS}_{\text{CHARGING}}$ – $\text{ANNUAL EMISSIONS}_{\text{DISCHARGING}}$)

**Where:**

$\text{ANNUAL EMISSIONS}_{\text{CHARGING}}$ =

$\text{ANNUAL EMISSIONS}_{\text{BASELINE CHARGING}}$ – $\text{ANNUAL EMISSIONS}_{\text{PROJECT CHARGING}}$

**AND**

$\text{ANNUAL EMISSIONS}_{\text{DISCHARGING}}$ =

$\text{ANNUAL EMISSIONS}_{\text{BASELINE DISCHARGING}}$ – $\text{ANNUAL EMISSIONS}_{\text{PROJECT DISCHARGING}}$

Illustrated in the 2015 emissions analysis, under current grid conditions, generation curtailment mitigation is the only application of electricity storage anticipated to result in a net reduction in GHG emissions per unit of electricity stored. Effectively, mitigating electricity curtailment with an emissions intensity lower than the grid is an improvement to the generator efficiency. Other applications (non-curtailment applications) tend to increase emissions because a storage charge/discharge cycle increases demand for electricity and the electricity in Alberta has a relatively high GHG intensity. This loss of power is considered a source of emissions in an ESS project.

Alberta's GHG quantification protocols address the GHG reductions from the curtailment mitigation at renewable energy projects (wind, solar, hydro). Section 9 discusses this further.

Current quantification protocols do not specify whether ESS projects integrated on the transmission grid have generated a verifiable emissions reduction. A single, grid-integrated ESS project may provide several differing services to multiple generators at any time. Thus, a facility of this nature could only generate verifiable emission reductions if the net emissions associated with all provided services result in a measurable reduction.

This also introduces a question regarding the methodology to determine the ownership of net emissions reductions generated by grid-integrated storage facilities. If ESS mitigates renewable energy curtailment, the ESS enables the emission reduction. However, displacing grid electricity with electricity generated at a lower emissions intensity creates the emission reduction. As the government revises the policies, it needs to develop a process for determining whether emission reductions are attributed to the proponent operating the storage facility or the power generator.

# 9 GHG EMISSION REDUCTION QUANTIFICATION FOR ENERGY STORAGE PROJECTS

The following section summarizes the approach to quantifying GHG emission reductions in Alberta. Specifically, this section references international best practices and summarizes the approved methodologies under Alberta's protocols to quantify emissions from projects that displace or use grid electricity.

Solas conducted an emissions analysis of various ESS technologies and applications using Alberta protocol methodologies and guidance documents. Solas documented the results of each storage scenario. Solas also explored the processes to monitor and verify the potential emissions reductions from ESS on a project basis.

## 9.1 Review of existing protocols/methodology in other jurisdictions and Alberta

Solas reviewed quantification protocols for the displacement of grid electricity or ESS. This included a review of protocols under the following programs:

- The Clean Development Mechanisms
- The World Resources GHG Protocol
- Climate Action Reserve (CAR)
- Alberta Offset System
- Regional Greenhouse Gas Initiative
- Western Climate Initiative
- ISO 14064 — Part 2: International Guidance on Quantifying Greenhouse Gas Emission Reductions from Projects

Solas did not identify any quantification protocols or guidance documents related to quantifying emissions associated with ESS. Solas developed a framework for quantifying emissions from ESS. Solas describes this framework below and explores the potential results of applying this framework, based on current (2015) and future (2030) grid conditions.

### 9.1.1 Introduction to quantification of GHG reductions

#### ISO 14064 — Part 2: International Guidance on Quantifying Greenhouse Gas Emission Reductions from Projects

In 2006, the ISO released an international standard for quantifying, monitoring, and reporting GHG reductions at the project level. This guidance document (The ISO Standard) is program neutral and uses terms and concepts compatible with other requirements and guidance from relevant GHG policies and programs, good practices, legislation, and standards.

The development of Alberta's Offset System referenced this ISO Standard. This standard also served as a reference in the development and review of all offset quantification protocols and facility emissions reporting standards to date.

### *Core principle of the ISO system*

Principles in this part of ISO 14064 intend to ensure a fair representation and a credible and balanced account of GHG emissions reductions from projects. The principles form the basis for justifications and explanations provided in determining the baseline, project, and net GHG emissions reductions. These principles, in summary, include Completeness, Consistency, Accuracy, Transparency, Relevance, and Conservativeness.

### *Fundamentals of quantifying GHG emission reductions*

As Section 8 identifies, the **baseline condition** for a project is a reasonable representation of conditions that would likely have occurred during a specified period had the project not been implemented. The **project condition** is a specific action targeted at reducing or removing GHG emissions.

### *Additionality*

The ISO Standard identifies additionality as required but does not provide direction on how to determine additionality. Additionality requires that a GHG project results in GHG emissions reductions "in addition" to what would have happened in the absence of that project.

### *GHG quantification boundaries*

The ISO Standard does not provide specific guidance regarding boundaries for GHG quantification, monitoring, and reporting. The ISO Standard discusses the concept of relevant GHG sources, sinks, and/or reservoirs.

Based on criteria and procedures selected or established, the project proponent shall list GHG sources, sinks, and reservoirs as:

- controlled by the project proponent,
- related to the GHG project, and
- affected by the GHG project.

### *Functional equivalence*

Emission reductions are calculated by comparing GHG emissions under one scenario (the project condition) with GHG emissions under another equivalent scenario (the baseline condition). For this comparison to be meaningful, the project and the baseline must provide the same function and quality of products or services. That is, both the project and baseline must use a common metric or unit of comparison.

### 9.1.2 Alberta's Offset System Protocols

Alberta has seven offset system quantification protocols approved under the regulatory Offset System related to displacing grid electricity with an alternative source. Alberta does not have any protocols that deal directly with ESS.

These seven quantification protocols are:

- Wind-Powered Electricity Generation — Mar 2008
- Solar Electricity Generation — May 2008
- Low-Retention, Water-Powered Electricity Generation as Run-of-the-River or an Existing Reservoir — May 2008
- Landfill Gas Capture and Combustion — Sep 22, 2015
- Anaerobic Treatment of Wastewater Projects
- Energy Generation from the Combustion of Biomass Waste — Apr 2014
- Distributed Renewable Energy Generation — Mar 2013

Two aspects are common to each of these protocols: the quantification methodology for determining the emissions associated with electricity displaced off the electricity grid, and the sources of emissions considered relevant and quantified in the project scenario. Solas discusses these aspects further below.

#### Quantifying grid emissions in Alberta

An electricity grid emission intensity factor reflects the emissions profile associated with the generation of one Megawatt-hour of electricity on the transmission grid. As such, it is used to quantify the emissions associated with the consumption of electricity, or, the emissions avoided by displacing grid electricity with an alternative source.

In Alberta, the regulatory authority has opted to implement a Marginal Intensity-based approach to quantifying electricity grid emissions. Common to the marginal intensity-based approaches is the consideration of the emission intensity of the Build Margin (BM) and Operating Margin (OM) to the electricity grid in question.

The Build Margin represents other capacity additions or the deployment of lower emissions electricity projects that may affect generator construction. Essentially, the BM is a measure of the longer-term effects that proposed electricity projects might have on the grid.

The Operating Margin represents new capacity additions that may affect the electricity generation of the mix of power generators on the grid. Essentially, it is a measure of the short-term effects that proposed electricity projects might have on the grid.

## 9.2 Integrating power storage with quantification protocols: Gap analysis

A variety of factors influence the emissions sources for the project condition of electricity storage projects. Table 18 summarizes these factors.

Solas determined each of these aspects by referencing the ISO 14064 standard guidance on quantifying project GHG emissions, as well as international best practice guidance on quantifying emissions from grid electricity. Solas considers the absence of specific guidance in Quantification Protocols on how to address these aspects gaps and explains these in greater detail below. Each gap is addressed below.

### 9.2.1 GAP 1: Protocols do not consider the GHG emissions impact associated with the energy source and the location of power storage

ESS can be located either:

(1) at the source of generation at a point before the connection to the transmission/distribution system and charging exclusively from the renewable energy generator; or
(2) integrated into the transmission/distribution system at a point after generation and before the connection with a load source; or
(3) at the load side of the connection with the transmission/distribution system.

If the source of the electricity used to charge a storage system would have otherwise been distributed on the electricity grid, the Marginal Intensity approach should be used to quantify the baseline condition. The charging source also impacts the emissions intensity of the project scenario. To accurately reflect the potential emission reductions enabled by ESS projects, further guidance on determining the boundary of an ESS project and the ownership of emission reductions is required.

### 9.2.2 GAP 2: Protocols do not consider the difference between power applications and energy applications for energy storage

Electricity storage technologies have varying capacities, as expressed as a unit of time. Solas groups these technologies into their applicability, power, or energy.

**Power Applications:** Technologies suitable for power applications, including power quality, spinning and non-spinning reserves, and ramping, are associated with shorter durations of storage discharge (less than one hour) and fast-responding discharge times. Because of the short-term duration of electricity storage for power applications, distribution to the grid results in displacing the marginal generator, whose electricity generation may be affected by new capacity additions. In referencing the Marginal Intensity Methodology previously discussed, the baseline emissions for charging and discharging for power applications would be more heavily weighted toward the OM of the ancillary service market, rather than the EMMO.

**Energy Applications:** Technologies with energy applications, including renewable capacity firming, non-spinning reserves, time-shifting, arbitrage, peaking capacity, are associated with much greater capacities (one hour or more) and longer discharge times. Thus, distribution of this stored electricity to the grid results in weighting the Marginal Intensity more heavily toward the BM. The BM is the types of power generators whose construction, in the future, may be affected by alternative capacity additions enabled through electricity storage.

For curtailment mitigation, spinning reserves and transmission and distribution asset deferral the baseline is determined by applying an equal weighting of the Build and Operating Marginal Intensities (see Table 20).

### 9.2.3 GAP 3: Protocols do not differentiate between energy markets and operating reserve markets

The energy market and the operating reserve market have distinctly different mix of generator types. The operating reserves market has specific requirements to participate that are technical in nature. To determine the OM of the OR market, Solas referenced the AESO's OR statistics, as reported through the AESO Electricity Trading System (ETS).

Figure 15 illustrates the mix of generators making up the OR in Alberta in 2015.

Solas determined the OM for both the 2015 and 2030 timeframes. Solas referenced the Alberta Climate Leadership Plan, for the 2030 for coal phase out to determine the generation mix of the OR market. The results of this analysis are shown in Figure 16.

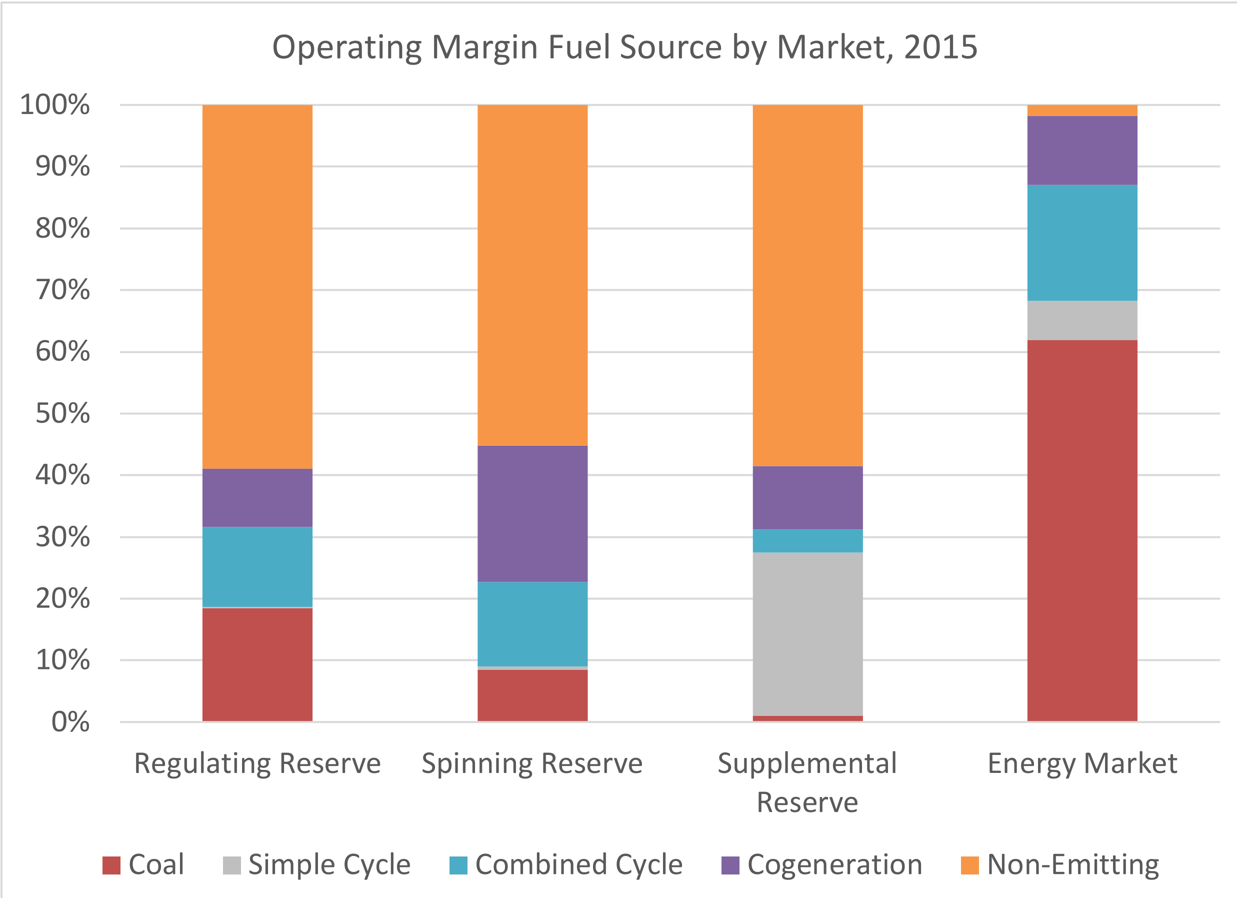



**Figure 15: Operating Reserves and Energy Market Generation Mix (2015)**

### 9.2.4 GAP 4: Protocols do not include the time of day at which electricity is charged and discharged (peak versus off-peak/low versus high price) and the relevant Operating Margin

Electricity price can influence charging and discharging electricity storage systems. The electricity price correlates to the time of day and electricity demand. Relevant applications include time-shifting (arbitrage), peaking capacity, and peak shaving.

On the current grid (2015), there is a pattern to the OM, where, during off-peak hours, coal-based generation drives the intensity of the OM higher.

A forward look to 2030, the Alberta Climate Leadership Plan is anticipated to reduce the intensity of the OM, as coal-powered generation is assumed to be replaced with combined-cycle natural gas. Thus, Alberta's electricity market's OM is also anticipated to become more consistent throughout the day

The OM by time-of-day in 2015 compared to 2030 is illustrated in Figure 16.

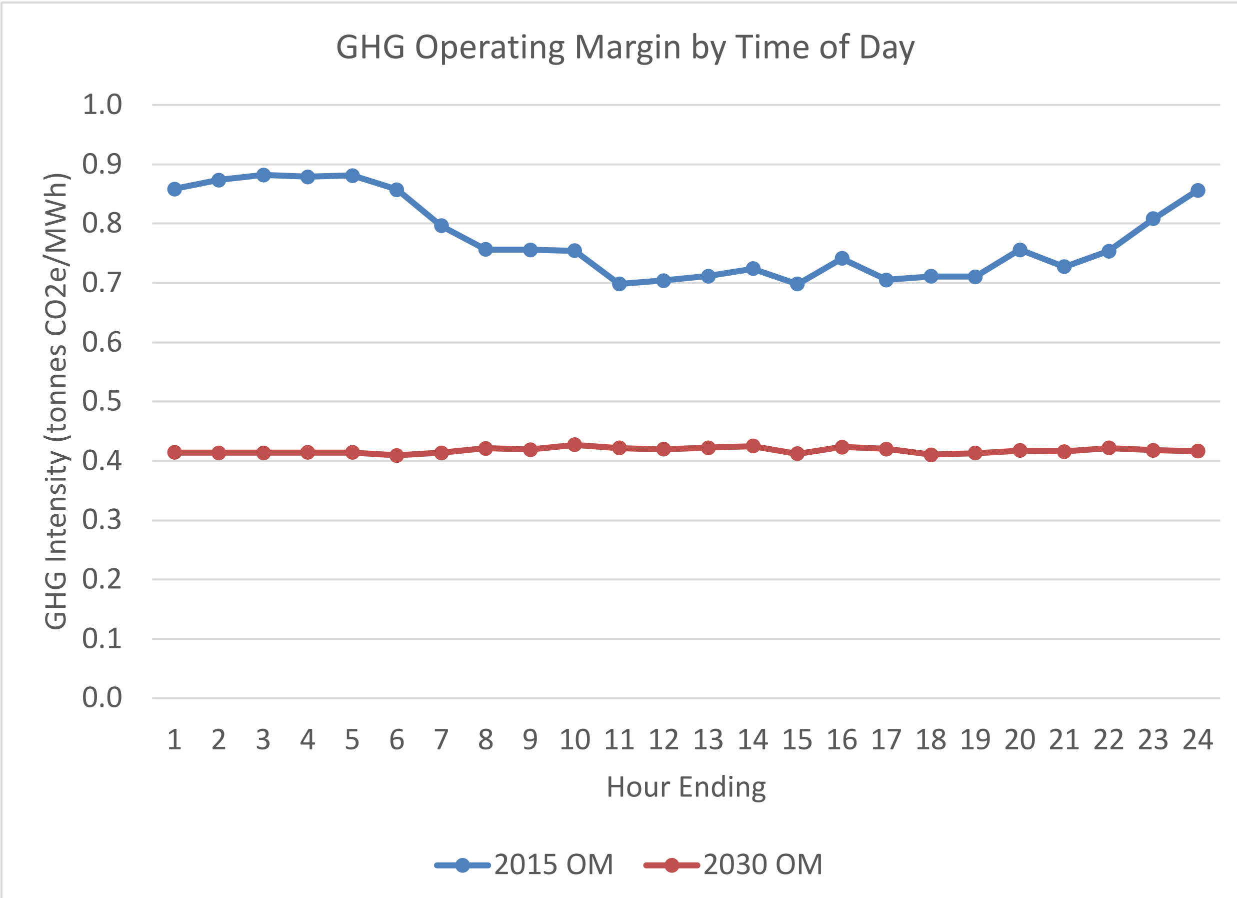



**Figure 16: Operating Margin of the Alberta Electricity Market by Time of Day**

### 9.2.5 GAP 5: Protocols do not include the impacts of congestion on transmission system losses

As discharging ESS displaces peak energy demand, and resulting distribution line losses are reduced. Since these losses are proportional to the square of the current flow, using ESS to shift some of this current or load from the peak period to off-peak period decreases the net resistive losses, further enhanced by the lower temperature of the line during off peak hours[52].

By reducing peak loading (and overloading), transmission and distribution lines become more efficient. The weighted average for line losses on the Transmissions and Distribution systems in

[52] Ali Nourai, Senior Member, IEEE, V. I. Kogan, Senior Member, IEEE, and Chris M. Schafer, Member, IEEE, *Load Leveling Reduces T&D Line Losses*, 2008

Alberta is 7.7 percent [53]. Thus, the baseline emissions intensity for distributed ESS projects is 0.64 tonnes $CO_2e$ / MWh in place of the typical grid displacement factor of 0.59 tonnes $CO_2e$ / MWh.

### 9.2.6 GAP 6: Protocols do not include the emissions intensity of partially loaded thermal plants

Some ESS applications can improve the efficiency of marginal thermal power generators and are only partially loaded. Partially loaded thermal plants demonstrate higher emissions intensities than those that have optimal loading. This is applicable when a storage technology can absorb excess energy in fast ramp-up situations and supply needed energy through fast ramp-down. These technologies typically support renewable energy ramping and spinning reserves.

Avoiding the need to deploy partially loaded plants with ESS improves the intensity of the OM. Determining this factor requires a significant amount of additional research.

### 9.2.7 GAP 7: Protocols do not include the specific type of storage technology

The ESS technology type determines the project-level emissions during operations. Capacitors and batteries require ozone-depleting substances with high global-warming potentials to cool these systems. CAES and hydro-pumping-based technologies require energy that may be fossil-fuel derived. Flywheels do not require any inputs that are sources of GHG emissions. Table 19 summarizes the inputs that would impact (both positively and negatively) the total project-level emissions.

**Table 19: Summary of Project Level Sources of GHG Emissions and GHG Reductions by Storage Technology**

| Technology | Input Task | Source of Project-Level Emissions | Source of Project-Level Reductions |
|---|---|---|---|
| Super capacitors | Cooling<br>System controls | Ozone-depleting substance and/or electricity | |
| Flywheels | System Controls | Electricity | |
| Power batteries | Cooling<br>System controls | Ozone-depleting substance and/or electricity | |
| Energy batteries | Cooling<br>System controls | Ozone-depleting substance and/or electricity | |
| I-CAES | Heating<br>System controls | Natural gas<br>Electricity | Recovered waste heat vs. typical CAES |
| CAES | Heating<br>System controls | Natural gas<br>Electricity | |
| Pumped hydro | System controls | Electricity | |

[53] Alberta Environment & Parks, *Emissions Factor Handbook*, March 2015

## 9.3 Potential emissions calculation methodology for storage

Of the seven approved Alberta Quantification Protocols related to electricity generation from various sources, none directly address integrated ESS options. Three documents, including the Protocols for wind, water, and solar-powered electricity generation, mention ESS as an integrated option and include emissions associated with ESS in the lifecycle quantification of net GHG emissions.

None of these documents provide direct guidance on what sources of emissions to consider in determining the impact of ESS on the baseline or project conditions. For each of the ESS technologies evaluated in this report, relevant sources of project emissions need to be identified to complete the lifecycle emissions analysis in alignment with ISO 14064 principles.

### 9.3.1 The baseline scenario

The baseline is considered in two parts for ESS projects: 1) the intensity of the electricity grid as electricity is being stored; 2) the intensity of the grid as electricity is discharged to the grid. The net of these two conditions provides a *complete* and *transparent* definition of the baseline scenario.

In 2017, AEP determined the most recent electricity grid displacement factor (EGDF) was 0.59 tonnes $CO_2e$ / MWh[54], as shown in Equation 3: Determining the Marginal Intensity of Alberta's Electricity Grid (Handbook Factor) and uses an equal weighting between operating margin and build margin.

**Equation 3: Determining the Marginal Intensity of Alberta's Electricity Grid (Handbook Factor)**

$$(0.5*OM) + (0.5*BM) = EGDF \text{ t } CO_2e / MWh$$

$$\text{Where, } OM = 0.696 \text{ t } CO_2e / MWh$$

$$\text{And } BM = 0.475 \text{ t } CO_2e / MWh$$

$$(0.5*0.696) + (0.5*0.475) = 0.59 \text{ t } CO_2e / MWh$$

For consistent analysis, Solas referenced 2015 provincial power generation data to estimate Alberta's EGDF of the electricity grid. Solas estimated the average 2015 operating margin to be 0.77 tonnes $CO_2e$ / MWh, as opposed to the 0.696 tonnes $CO_2e$ / MWh provided by AEP. Details are not available from AEP on the AEP operating margin calculation resulting in 0.696 tonnes CO2e/MWh. Herein, Solas refers to this factor of 0.77 tonnes $CO_2e$ / MWh as **OM2015.**

[54] Alberta Environment & Parks, *Emissions Factor Handbook*, March 2015

Considering Alberta's Climate Leadership Plan's regulatory impacts on electricity generation, Solas estimates the average operating margin of Alberta's Electricity Grid in 2030 will be as low as 0.42 t $CO_2e$ / MWh, herein referred to as **OM2030**.

**Marginal Intensity Analysis:** To illustrate the impact of the factors that influence the marginal intensity of Alberta's electricity grid, Solas analysed each of the storage applications and associated technologies. Table 20 summarizes these technology-specific storage capacities. Each of the cases assumed a 10 MW charge/discharge capability, with the MWh capacity varying by technology. For the sake of simplicity, Solas assumed system efficiency to be 90 percent for all technologies, except for CAES technologies, which Solas assumed to be 75 percent for i-CAES. For CAES, the burning of natural gas during the discharge process is assumed to result in 1.3 MWh returned to the grid for every MWh stored. The calculation of round-trip efficiency for CAES is complicated but is approximately 50 percent based on the assumptions used in the analysis here.

**Table 20: Capacity/ Duration by Electricity Storage Technology**

| Technology | Technology Code | Energy Capacity /Duration (hours) |
|---|---|---|
| Super capacitor | i | 0.2 |
| Flywheel | ii | 0.5 |
| Power battery | iii | 1 |
| Energy battery | iv | 2 |
| i-CAES | v | 4 |
| CAES | vi | 7 |
| Pumped hydro | Vii | 200 |

Table 21 summarizes the relevant data by fuel type used to determining the variable OM and BM inputs and the resulting marginal intensity of the electricity grid.

Solas analysed marginal intensity using generation-facility specific emissions data. For this analysis, Solas determined emissions intensities for coal, SCGT, and CCGT by referencing proxy-facility emissions data in Alberta for 2014, as extracted from the National Pollutant Release Inventory[55].

**Table 21: Estimated Emissions Intensity (tonnes CO2e / MWh of generation) by Fuel Source**

| | Facility | Total Emissions (Tonnes $CO_2e$) | Total Exports (MWh) | Emissions Intensity (Tonnes $CO_2e$/MWh) |
|---|---|---|---|---|
| CCGT | Calgary Energy Centre — CCGT | 402,407 | 969,340 | 0.42 |
| Coal | Genesee 1,2,3 — Coal | 9,166,664 | 9,710,355 | 0.94 |
| | Keephills 1,2,3 — Coal | 9,431,798 | 9,116,533 | 1.04 |

[55] National Pollutant Release Inventory, 2014. http://ec.gc.ca/ges-ghg/donnees-data/index.cfm?do=search&lang=en

| | Facility | Total Emissions (Tonnes $CO_2e$) | Total Exports (MWh) | Emissions Intensity (Tonnes $CO_2e$/MWh) |
|---|---|---|---|---|
| | *Coal Average* | | | *0.99* |
| SCGT | Carseland Power Plan - SCGT[56] | 337,939 | 550,879 | 0.61 |
| Cogeneration | Cogeneration | | | 0.34[57] |

The OM for ESS applications that would participate in Alberta's OR Market would differ from that of the SGER2015 factor and the SGER2030 forecast. In addition, ESS applications that enable responses to time-of-day pricing and demand for electricity would charge and discharge electricity when the operating margin's intensity differs throughout the day.

A comparison to 2015 OM, BM and 2030 OM and BM is shown below.

**Table 22: Summary of Operating and Build Margins used for 2015 and 2030**

| | 2015 | 2030 | Notes |
|---|---|---|---|
| **Alberta Power Pool** | t $CO_2e$ / MWh | t $CO_2e$ / MWh | |
| Operating Margin | 0.770 | 0.420 | |
| Build Margin | 0.475 | 0.475 | |
| Electricity Grid Displacement Factor | 0.590 | 0.445 | Using methodology identified in the Handbook Factor issued by AEP |
| **Operating Reserves** | t $CO_2e$ / MWh | t $CO_2e$ / MWh | |
| Build Margin for Peaking Capacity, Spinning Reserve, Non-spinning Reserve and Peak Shaving | | 0.620 | Assumed to be Simple Cycle Gas Turbine |
| Other services | | 0.417 | Assumed to be Combined Cycle Gas Turbine |

Solas chose the weighting factors for the OM and the BM for ESS, based on the ESS application's ability to displace the requirement for new capacity. Where the ESS application could displace new generation capacity, the BM had a higher weighting. Where the ESS application would reduce dispatch of existing generation, the OM had a higher weighting. Otherwise this was considered to have equal weighting. The weighting factors for the BM and the OM are shown in the following table.

[56] CEC Knowledge Network, North American Power Plan Air Emissions, www2.cec.org
[57] Evaluating the role of cogeneration for carbon management in Alberta, G.H. Doluweera, S.M. Jordaan, M.C. Moore, D.W. Keith, J.A. Bergerson, Page 9, table 4, 2011

### Table 23: Storage Application Specific Assumptions in Determining the Marginal Intensity[58] of Alberta's Electricity Grid (2015)

| ESS Application | Code | OM: Charging | OM: Discharge | BM | OM Ratio | BM Ratio | Marginal Intensity Charging | Marginal Intensity Discharge | Considerations/ Justification |
|---|---|---|---|---|---|---|---|---|---|
| Renewable capacity firming | REF | OM2015 | OM2015 | CCGT | 25 percent | 75 percent | 0.50 | 0.50 | Storage enables firm capacity delivery, reducing the need to build additional generation. Average build margin displaced. |
| Renewable ramping | RER | OM2015 | OM2015 | CCGT | 75 percent | 25 percent | 0.67 | 0.67 | Emissions intensity of loaded operating facilities connected to the grid improved. Operating margin determined by modelling efficiency improvement in thermal generators. |
| Renewable smoothing | RES | OM2015 | OM2015 | CCGT | 75 percent | 25 percent | 0.67 | 0.67 | Operating margin determined by modelling efficiency improvement in thermal generators |
| Curtailment mitigation | CURT | OM2015 | OM2015 | CCGT | 50 percent | 50 percent | 0.59 | 0.59 | Baseline justified with grid displacement factor of 0.59 because power pulled off the grid. |
| Time-shifting/ Arbitrage | ARB | low15 | high15 | CCGT | 75 percent | 25 percent | 0.76 | 0.62 | Operating margin constrained by the operating margin's intensity based on time of day (peak versus non-peak). |
| Peaking capacity | PKCAP | low15 | high15 | SCGT | 75 percent | 25 percent | 0.78 | 0.64 | Operating margin constrained by the operating margin's intensity based on time of day (peak versus non-peak). |

[58] All intensities are expressed as Tonnes $CO_2e$ per MWH

| ESS Application | Code | OM: Charging | OM: Discharge | BM | OM Ratio | BM Ratio | Marginal Intensity Charging | Marginal Intensity Discharge | Considerations/ Justification |
|---|---|---|---|---|---|---|---|---|---|
| Spinning reserve | SRES | SPINR15 | SPINR15 | SCGT | 50 percent | 50 percent | 0.36 | 0.36 | No time-of-day impact. Therefore, operating margin determined by taking an average marginal intensity of all facilities on the grid. |
| Non-spinning reserve (Supplementary reserve) | NSRES | SUPR15 | SUPR15 | SCGT | 25 percent | 75 percent | 0.42 | 0.42 | No time-of-day impact. Therefore, operating margin determined by taking an average marginal intensity of all facilities on the grid. |
| Frequency Regulation | FREG | REGR15 | REGR15 | CCGT | 75 percent | 25 percent | 0.31 | 0.31 | Energy provided to the grid on a basis unrelated to energy market of pricing. Operating margin is grid average. |
| Frequency response | FRES | REGR15 | REGR15 | CCGT | 75 percent | 25 percent | 0.31 | 0.31 | 7.7 percent in line losses, as per CASA study and Distributed Generation Protocol. |
| T&D asset deferral | TD | SGER | SGER | CCGT | 50 percent | 50 percent | 0.56 | 0.56 | Baseline is justified with grid displacement factor of 0.59 because power pulled off the grid. |
| Peak shaving | PKSHV | low15 | high15 | SCGT | 75 percent | 25 percent | 0.78 | 0.64 | Baseline justified with grid displacement factor of 0.59 because power pulled off the grid. |
| Time-shifting | TSHIFT | OM2015 | OM2015 | CCGT | 75 percent | 25 percent | 0.67 | 0.67 | Based on the generator’s marginal intensity, which provides power to the storage system. |
| UPS | UPS | OM2015 | OM2015 | CCGT | 75 percent | 25 percent | 0.67 | 0.67 | Based on the generator’s marginal intensity, which provides power to the storage system. |

| ESS Application | Code | OM: Charging | OM: Discharge | BM | OM Ratio | BM Ratio | Marginal Intensity Charging | Marginal Intensity Discharge | Considerations/ Justification |
|---|---|---|---|---|---|---|---|---|---|
| Power quality | PQ | OM2015 | OM2015 | CCGT | 75 percent | 25 percent | 0.67 | 0.67 | Storage enables firm capacity delivery, reducing need to build additional generation. Average build margin displaced. |

### 9.3.2 The Project Scenario

In each of the Protocols, the approach to quantifying project emissions includes common relevant emissions sources identified in the lifecycle emissions analysis. These common emissions sources, which include quantifying projects emissions and which Solas considers relevant, include the following:

- Transportation (tailpipe) emissions associated with getting the fuel used to generate electricity to site (i.e., the transportation of biofuels or biomass to a combustion facility).
- On-site emissions related to treating fuel source at a power generation facility, which could include the storage and potential decomposition of biomass residuals and the storage of liquid or compressed fuels on a site.
- On-site emissions associated with operating a power generation facility that may require combusting hydrocarbons, consuming electricity, or using ozone-depleting substances as a coolant.
- Emissions associated with how the fuel source energy converts to electricity, including fuel combustion.
- The upstream emissions associated with extracting and processing hydrocarbons consumed in the activities identified in all project activities noted above.

Solas determined project emissions were immaterial for all ESS applications except for CAES. In CAES, natural gas is combusted in the discharge process.

### 9.3.3 Analysis of the net GHG emissions intensity of ESS (2015 and 2030) by technology, location, and application

Solas analysed the net GHG emissions intensity of ESS to illustrate whether emission reductions were enabled or generated.

Table 24 presents the estimated emissions intensity for each ESS technology in 2015 by location and application. Table 25 presents the 2030 estimates.

The report identifies the efficiency assumption for each technology[59]. Technology specific efficiencies may be higher or lower than those reported and used in the calculation. Therefore, there is some uncertainty associated with the results shown below, but the results can be used as a general guideline for these technologies applied in the Alberta grid.

[59] FIND THE SECTION

The abbreviations used in the next table are identified here:

| | | | |
|---|---|---|---|
| **Types of ESS Technology** | | | |
| S.C. | Supercapacitor | i-CAES | Isothermal-Compressed air energy storage |
| F.W. | Flywheel | CAES | Compressed air energy storage |
| P. Batt | Power Battery | P. Hydro | Pumped Hydro |
| E. Batt | Energy Battery | | |
| **Energy storage applications** | | | |
| REF | Renewable capacity firming | FREG | Frequency Regulation |
| RER | Renewable ramping | FRES | Frequency Response |
| RES | Renewable smoothing | TD | Transmission and Distribution |
| CURT | Curtailment mitigation | PKSHV | Peak Shaving |
| ARB | Arbitrage | TSHIFT | Time Shifting |
| PKCAP | Peaking Capacity | UPS | Uninterrupted Power Source |
| SRES | Spinning reserves | PQ | Power Quality |
| NSRES | Non-Spinning reserves | | |

**Table 24: Estimated GHG Emissions Intensity of ESS (2015)** *(Red is an increase in emissions, Green is a decrease in emissions)*

| GHG Impact of ESS Technologies (tonnes $CO_2$e per MWh, 2015) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Loca-tion | Tech-nology | Application | | | | | | | | | | | | | | |
| | | REF | RER | RES | CURT | ARB | PKCAP | SRES | NSRES | FREG | FRES | TD | PKSHV | TSHIFT | UPS | PQ |
| At Generator | S.C. | | | | | | | | | | | | | | | |
| | F.W. | | 0.08 | 0.07 | | | | 0.05 | 0.06 | 0.02 | 0.02 | | | | | |
| | P. Batt | | 0.08 | 0.07 | | | | 0.05 | 0.06 | 0.02 | 0.02 | | | | | |
| | E. Batt | 0.06 | 0.08 | 0.07 | 0.59 | 0.22 | 0.22 | 0.05 | 0.06 | 0.02 | 0.02 | | | | | |
| | i-CAES | 0.17 | | | 0.59 | 0.39 | 0.40 | 0.14 | 0.18 | 0.09 | 0.09 | | | | | |
| | CAES | | | | | | | | | | | | | | | |
| | P.Hydro | | | | | | | | | | | | | | | |
| On Transmission Grid | S.C. | | | | | | | | | | | | | | | |
| | F.W. | | 0.08 | | | | | | | 0.02 | 0.02 | | | | | |
| | P. Batt | | 0.08 | | | | | 0.05 | 0.06 | 0.02 | 0.02 | | | | | |
| | E. Batt | | 0.08 | | 0.59 | 0.22 | 0.22 | 0.05 | 0.06 | 0.02 | 0.02 | 0.02 | | | | |
| | i-CAES | | | | 0.59 | 0.39 | 0.40 | 0.14 | 0.18 | 0.09 | 0.09 | 0.14 | | | | |
| | CAES | | | | 0.32 | 0.23 | 0.21 | 0.17 | 0.15 | 0.20 | 0.20 | 0.10 | | | | |
| | P.Hydro | | 0.08 | | 0.32 | 0.22 | 0.22 | 0.05 | 0.06 | 0.02 | 0.02 | 0.02 | | | | |
| At Load | S.C. | | | | | | | | | | | | | | 0.17 | 0.10 |
| | F.W. | | | | | | | | | 0.02 | | | 0.23 | | 0.11 | 0.08 |
| | P. Batt | | | | | | | 0.05 | 0.06 | 0.02 | | | 0.22 | | 0.08 | 0.08 |
| | E. Batt | | | | 0.59 | | | 0.05 | 0.06 | 0.02 | | | 0.22 | 0.08 | | |
| | i-CAES | | | | 0.59 | | | 0.14 | 0.18 | 0.09 | | | 0.40 | 0.23 | | |
| | CAES | | | | | | | | | | | | | | | |
| | P.Hydro | | | | | | | | | | | | | | | |

**Table 25: Estimated GHG Emissions Intensity of Electricity Storage (2030) – Based on AESO Long Term Outlook 2016** *(Red is an increase in emissions, Green is a decrease in emissions)*

| GHG Impact of ESS Technologies (tonnes $CO_2e$ per MWh, 2030) | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Loca-tion | Tech-nology | Application | | | | | | | | | | | | | | |
| | | REF | RER | RES | CURT | ARB | PKCAP | SRES | NSRES | FREG | FRES | TD | PKSHV | TSHIFT | UPS | PQ |
| At Generator | S.C. | | | | | | | | | | | | | | | |
| | F.W. | | 0.05 | 0.04 | | | | 0.05 | 0.06 | 0.01 | 0.01 | | | | | |
| | P. Batt | | 0.05 | 0.04 | | | | 0.04 | 0.06 | 0.01 | 0.01 | | | | | |
| | E. Batt | 0.05 | 0.05 | 0.04 | 0.42 | 0.05 | 0.06 | 0.04 | 0.06 | 0.01 | 0.01 | | | | | |
| | i-CAES | 0.14 | | | 0.42 | 0.14 | 0.16 | 0.13 | 0.17 | 0.06 | 0.06 | | | | | |
| | CAES | | | | | | | | | | | | | | | |
| | P.Hydro | | | | | | | | | | | | | | | |
| On Transmission Grid | S.C. | | | | | | | | | | | | | | | |
| | F.W. | | 0.05 | | | | | | | 0.01 | 0.01 | | | | | |
| | P. Batt | | 0.05 | | | | | 0.04 | 0.06 | 0.01 | 0.01 | | | | | |
| | E. Batt | | 0.05 | | 0.42 | 0.05 | 0.06 | 0.04 | 0.06 | 0.01 | 0.01 | 0.01 | | | | |
| | i-CAES | | | | 0.42 | 0.14 | 0.16 | 0.13 | 0.17 | 0.06 | 0.06 | 0.10 | | | | |
| | CAES | | | | 0.15 | 0.17 | 0.16 | 0.18 | 0.15 | 0.21 | 0.21 | 0.15 | | | | |
| | P.Hydro | | 0.05 | | 0.42 | 0.05 | 0.06 | 0.05 | 0.06 | 0.01 | 0.01 | 0.01 | | | | |
| At Load | S.C. | | | | | | | | | | | | | | 0.14 | 0.07 |
| | F.W. | | | | | | | | | 0.01 | | | 0.06 | | 0.08 | 0.05 |
| | P. Batt | | | | | | | 0.04 | 0.06 | 0.01 | | | 0.06 | | 0.05 | 0.05 |
| | E. Batt | | | | 0.42 | | | 0.04 | 0.06 | 0.01 | | | 0.06 | 0.05 | | |
| | i-CAES | | | | 0.42 | | | 0.13 | 0.17 | 0.06 | | | 0.16 | 0.14 | | |
| | CAES | | | | | | | | | | | | | | | |
| | P.Hydro | | | | | | | | | | | | | | | |

The results show that there is no clear and simple answer to the question of whether ESS projects generate emission reductions. There is a wide range in GHG impacts of ESS. In some situations, there are emission reductions, whereas in others there are increased levels of emissions. The results range by technology and application.

- For the same technology, there can be differences in GHG emissions depending on the application this technology.
- The same application can have a wide range of emissions depending on the technology.

In general, i-CAES has the highest emissions intensity when deployed in Alberta in the 2015 timeframe. The highest emissions intensity applications include arbitrage, peaking capacity and peak shaving applications.

The technology with the lowest emissions is flywheels and power batteries. The lowest emissions for ESS applications include renewable energy curtailment mitigation. The analysis shows that the location of the ESS is not a factor in the emissions profiles.

Curtailment mitigation reduces GHG emissions through ESS. This scenario considers renewable energy being curtailed. ESS, in this case, allows for the continued generation of renewable energy and therefore reduces GHG emissions compared to the base case.

All other ESS applications show an increase in emissions in the Alberta 2015 and 2030 grid. The result that all other applications increase GHG emissions is due to a combination of three factors:

- ESS facilities are not 100 percent efficient;
- the electricity that is lost through the technology efficiencies must ultimately come from the grid;
- the grid in Alberta has a high level of GHG emissions.

Figure 17 illustrates the change in emissions for a battery connected to the transmission grid performing arbitrage. During the charging hours, the addition of the battery in the Project Case increases generation from the grid compared to the base case. In the hours when the battery is discharging, the addition of the battery decreases the generation from the grid compared to the base case. Since the battery is not completely efficient, the energy provided during discharge hours is less than the energy taken during charging hours. Multiplying the lost energy volume by the Electricity Grid Displacement Factor results in the increase in emissions due to the battery.

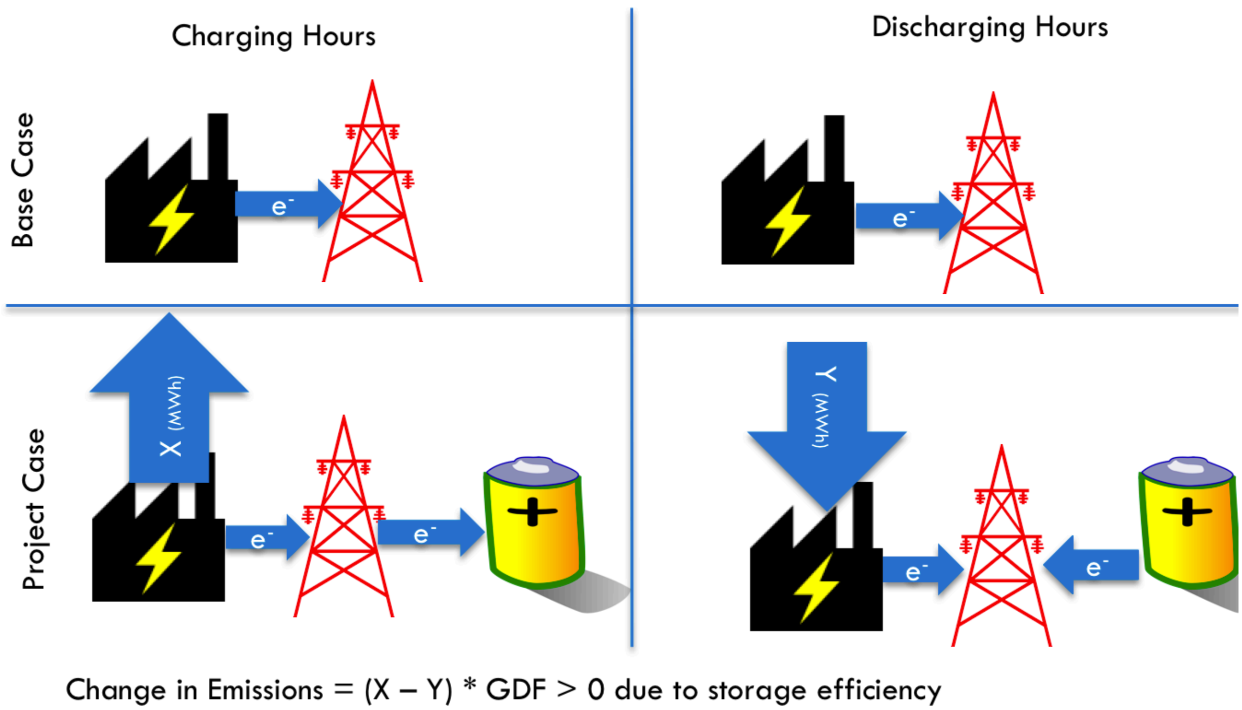



**Figure 17: Quantification of GHG Emissions: Arbitrage, On Grid, Battery**

The emission increase from the charging hours are now added to the emission reductions from the discharging hours. In the analysis, batteries were assumed to be 90 percent efficient so the energy needed in the charging hours was greater than the energy delivered in the discharging hours, and the lost energy is replaced by grid energy with a non-zero emissions factor and so, therefore, total emissions have increased.

The situation for quantification of GHG emissions for batteries located at the generator is shown below in Figure 18. This figure illustrates the change in GHG emissions for a battery performing arbitrage but co-located with a wind farm. In this situation, wind energy is used to charge the battery. In the charging hours, generation on the grid increases compared to the base case to make up for the diverted wind power.

In the discharging hours, grid generation is reduced by the energy delivered to the grid by the battery. The net result is the same as the transmission connected case, with an increase in emissions that is dependent on the technology efficiency and the electricity grid displacement factor.

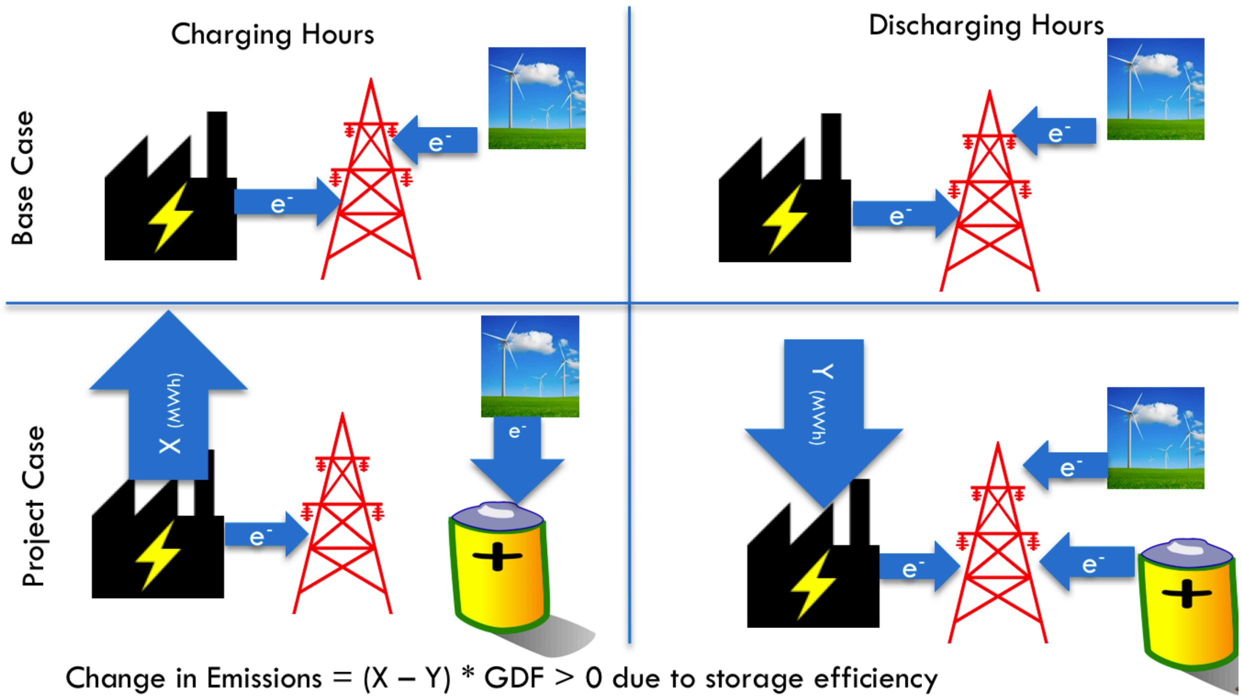



**Figure 18: Quantification of GHG Emissions: Arbitrage, At Generator, Battery**

The diagram showing the quantification of GHG Emissions for curtailment avoidance at the generator for batteries is shown below in Figure 19. In this case charging the battery does not change the grid generation since the electricity was curtailed in the base case. Applications such as peak shaving, spinning reserve, and others have increased emissions, due to the mechanism shown in the figure above.

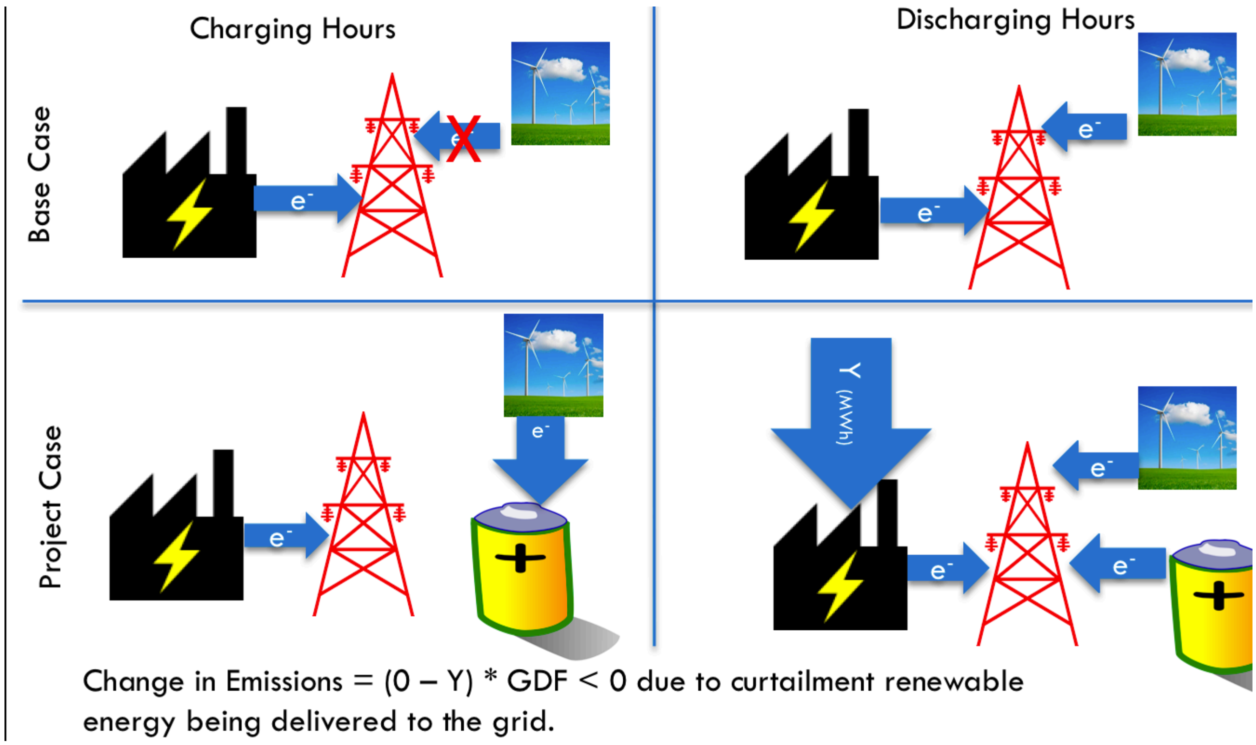



**Figure 19: Quantification of GHG Emissions: Curtailment Avoidance, At Generator, Battery Application**

i-CAES has the highest emissions because the technology is currently less efficient than the other technologies. Arbitrage, peaking capacity and peak shaving applications have higher emissions because they are assumed to be time-of-day dependent. For these three applications, charging would generally occur at night, when the price is typically lower but marginal grid intensity is higher than during the peak hours of the day, which is when discharging is assumed to occur (see Figure 16). In 2030, the emissions intensity is more even across the time-of-day and these three applications have emission profiles like other applications.

At the project level, it is only through curtailment mitigation that an ESS project generates GHG emission reductions, all other applications result in an increase in GHG emissions. The volume of the GHG increase becomes less significant as storage becomes more efficient and the grid becomes cleaner.

These results must be placed in the greater context of two considerations. The first is that ESS technologies provide value in several ways, for example, the ability for fast responding ESS technologies to reduce the volume and cost of regulating reserve. To reduce the discussion of ESS to arbitrage applications is to ignore the thirteen other applications for ESS technologies.

The second consideration is to recognise that curtailment is a powerful tool for system operators to use to maintain grid reliability and is not likely to be underutilized. The Pan-Canadian Wind

Integration Study found a significant increase in curtailment as wind energy integration increased even to the 35 percent level. Further studies will be needed to understand the potential for curtailment in Alberta.

## 9.4 Limitations of the Analysis

The analysis was limited in the number of scenarios that were developed. Also, the project specific nuances have not been integrated, but rather more general assumptions have been used. The analysis does not account for the improving efficiencies for each technology over time for round-trip efficiency. Solas has assumed the AESO 2016 long term outlook for the system mix in 2030. The results are also dependent on the ESS technology operating parameters as the analysis assumes they remain as are in 2016.

# 10 DOES ENERGY STORAGE ENABLE EMISSION REDUCTIONS?

The quantitative evaluation of whether ESS creates emission reductions and how much is created is a simpler task than determining if ESS enables emission reductions in general. This section first shows how ESS projects create emission reductions through curtailment mitigation and then discusses more generally how ESS enables renewable energy integration and emission reductions.

## 10.1 Curtailment Mitigation Opportunities through Energy Storage

ESS projects enable emission reductions through reduction of curtailment of renewable energy. Curtailment can result from three effects: transmission constraints, ramping constraints, and supply surplus. There is limited information available on current curtailment practices since AESO only reports curtailment on an aggregated basis. Solas has evaluated the potential size of emission reductions through the deployment of ESS for curtailment mitigation.

Solas created two scenarios: 2030 and 2050. The 2030 scenario is based on the AESO 2016 Long Term Outlook (LTO) reference case demand and generation mix with incremental wind capacity of 5,000 MW starting at 400 MW per year in 2019 and increasing to 425 MW per year by 2023.

The 2050 demand scenario was extrapolated from AESO 2016 LTO reference case growth rate from 2030 to 2037. To create the generation mix in 2050, Solas assumed that all new load is supplied from wind power. This assumption indicates that by 2030 the electricity policy has shifted to restrict any new thermal generation and meet the Provincial and Federal obligations domestically and internationally. In addition, this scenario assumes that simple cycle and combined cycle capacity installed prior to 2022 has been retired due to age and replaced by wind capacity on a one-to-one basis. The result is wind capacity additions of 500 MW per year from 2030 to 2050 which results in total installed wind capacity of 16,600 MW, or 55 percent of total Alberta generation capacity at that time.

The assumption is made for three reasons:

1) simplicity, rather than trying to estimate the new supplies of solar, hydro, biomass, geothermal, or even new natural gas, no matter how likely they may be. Solas recognises that deployment will be a mixture of renewable energy sources, both baseload and variable.
2) The assumption represents a future direction rather than trying to make a specific prediction.
3) The all-wind assumption provides an upper bound for curtailment potential in 2050. Other scenarios that replace wind with other renewables or increase natural gas capacity would likely have less curtailment.

The wind power and total generation capacity assumptions are summarized in Table 26. The analysis also estimates the Electricity Grid Displacement Factor (EGDF) and emission reduction potential for each scenario.

**Table 26: Wind Power Capacity, Total Generation Capacity for 2015, 2030 and 2050 Scenarios**

| Year | Wind Power Capacity (MW) | Total Generation Capacity (MW) | Wind Percent of Capacity | EGDF (tonnes $CO_2e$/MWh) |
|---|---|---|---|---|
| 2015 | 1,463 | 16,288 | 9% | 0.59 |
| 2030 | 6,463 | 24,222 | 27%[60] | 0.40 |
| 2050 | 16,611 | 30,245 | 55% | 0.14 |

Wind energy production in newly developed regions is based on results from the Alberta Wind Vision Technical Overview Report[61].

### 10.1.1 Transmission constraints

The May 2016 AESO project list identifies 6,079 MW of wind projects by planning area, which is more than sufficient to meet the 2030 wind capacity target.

Solas identified the AESO planning areas that are subject to RAS in 2016. Solas assumes that curtailment will persist for eight years after connection until transmission constraints are ameliorated in the locations that have RAS in 2016. This is the typical development cycle for transmission lines in Alberta. Solas also assumes a 25 percent curtailment for each project developed in an area affected by RAS in 2016. Solas based this on its understanding of the RAS impact on the Pincher Creek region.

Table 27 shows the estimated curtailed energy due to transmission congestion in 2030 and 2050. The table also shows the emission reduction potential available from integrating ESS to mitigate the curtailment and the required volume of ESS assuming one storage charge/discharge cycle per day.

60 Including 894 MW of existing hydro brings the 2030 installed renewable capacity to 30 percent, consistent with the Climate Leadership Plan.
61 Wind data provided courtesy of CanWEA.

**Table 27: Curtailed Energy, Emission Reduction Potential and Storage Potential due to Transmission Constraints in Years 2030 and 2050.**

| Scenario | Curtailed Energy (MWh) | Potential Emission Reductions (tonnes $CO_2e$) | ESS Potential (MWh) |
|---|---|---|---|
| 2030 | 1,160,774 | 464,310 | 3,180 |
| 2050 | 4,445,019 | 800,103 | 12,178 |

The estimates of curtailed energy and emission reduction potential will be reduced if transmission development matches the pace of renewable energy deployment. The economic evaluation of transmission build and ESS as a transmission asset deferral is beyond the scope of this report.

### 10.1.2 Ramping constraints

For the 2030 and 2050 scenarios, conventional generation was dispatched on an hourly basis to match the net demand, defined as a load minus wind. Wind power production was based on the wind data provided by CanWEA in the Alberta WindVision Technical Report. Hourly up and down ramping limits for combined cycle and single cycle gas facilities were based on historical dispatch data for each generation type. Based on historical data, Solas assumed one-third of installed cogeneration capacity is available for dispatch into the energy market while the other two-thirds are operating behind-the-fence to meet local industrial process requirements. The merchant cogeneration capacity and "other" generation capacity was assumed to have ramp rates equal to CCGT. Hydro was assumed to be able to ramp from zero to full capacity within one hour.

Where the ramping capability of the system was insufficient to meet the change in net demand, either wind generation was curtailed, or a loss load event was identified. The results of the curtailment associated with ramping constraints are shown in Table 28: Curtailed Energy, Potential Emission Reductions and Storage Requirement due to Ramping . The table shows the storage charge/discharge capacity required to capture the largest single hour curtailment.

**Table 28: Curtailed Energy, Potential Emission Reductions and Storage Requirement due to Ramping Constraints**

| Scenario | Curtailed Energy (MWh) | Potential Emission Reductions (tonnes $CO_2e$) | Storage Requirement (MW) for the single largest event in one hour. |
|---|---|---|---|
| 2030 | 0 | 0 | 0 |
| 2050 | 87,053 | 12,129 | 2,656 |

There is no curtailment due to ramping events in 2030 when renewable energy is 30 percent, and the curtailed volume in 2050 is about two percent of the volume compared to transmission curtailment in 2050.

### 10.1.3 Supply Surplus

Solas used the same dispatch analysis used for ramping identification to also determine supply surplus curtailment. Supply surplus hours occur when the net load is less than the baseload amount supplied by cogeneration to meet industrial requirements in this scenario. The curtailed energy and potential emission reductions are shown in Table 29. The table also shows the storage requirement to capture the largest single hour of supply surplus.

**Table 29: Curtailed Energy, Potential Emission Reductions and Storage Requirement due to Supply Surplus**

| Scenario | Curtailed Energy (MWh) | Potential Emission Reductions (tonnes $CO_2e$) | Storage Requirement (MW) for the largest single event. |
|---|---|---|---|
| 2030 | 0 | 0 | 0 |
| 2050 | 4,990,592 | 695,319 | 6,730 |

As with ramping, no supply surplus hours were identified in the 2030 scenario. This issue was only apparent in the 2050 scenario. The curtailed energy in 2050 from supply surplus was 10 percent higher than the curtailed energy due to transmission constraints.

### 10.1.4 Summary of Emission Reduction potential from Curtailment Mitigation

The parameters that affect curtailment levels primarily include demand growth, generation deployment and transmission development. The following table provides a summary of the results of Solas' estimate of the potential curtailment mitigation for the single year 2030 and 2050. This shows that the opportunity for ESS to reduce emissions in 2030 is significant and is almost in the same order as 50 percent of the Shell Quest Carbon Capture and Storage project. The opportunity stems from Transmission constraints, rather than ramping or supply surplus.

In 2050, the potential of emission reductions by ESS is greater than 2030 by almost three times. The opportunity is primarily from transmission constraints and supply-surplus event occurrences.

**Table 30: Alberta GHG emission reductions by ESS from the mitigation of Renewable Energy Curtailment) in the year 2030 and 2050.**

| Tonnes GHG Emission Reductions (Annual Tonnes $CO_2$e) | Transmission Constraints | Ramping Constraints | Supply Surplus | Total |
|---|---|---|---|---|
| 2030 | 464,310 | 0 | 0 | 464,310 |
| 2050 | 622,303 | 12,129 | 695,319 | 1,329,750 |

Table 30 demonstrates the potential opportunity for emission reductions that ESS could mitigate; however, the economics of this mitigation will likely reduce the numbers shown. The economics will change over time as ESS technologies advance in efficiency and reduce in cost. Both are expected.

## 10.2 Does ESS enable emission reductions?

The answer for whether ESS enables emission reductions depends on the curtailment levels of renewable energy and the integration levels of renewable energy. Table 31 below shows three different scenarios for renewable energy integration levels (Low, Medium, High) and three levels of renewable energy curtailment (Low, Medium, High). For each of these scenarios, the level of emission reductions generated resulting from the introduction of ESS varies.

- At low levels of renewable energy integration, ESS can create emission reductions by reducing renewable energy curtailment. Higher levels of curtailment mean that ESS has greater value and creates more emission reductions.
- At medium levels of renewable energy integration, ESS can provide higher levels of emission reductions since there is a higher likelihood of curtailment.
- At high levels of renewable energy integration there is an increased likelihood of curtailment, however, there are fewer emissions from the grid, so ESS improves the ability for renewable energy to be integrated, but few or no emission reductions are generated.

**Table 31: Renewable Energy Levels, Curtailment and Potential for GHG Emission Reductions through ESS Deployment**

| | | Renewable Energy Integration Levels | | |
|---|---|---|---|---|
| | | Low RE Levels | Medium RE levels | High RE Levels |
| Curtailment | Low Curtailment Levels | Few emission reductions | Limited emission reductions | Few or no emission reductions |
| | Medium Curtailment Levels | Mid-Level emission reductions | High level of emission reductions | Few or no emission reductions |
| | High Curtailment Levels | High emission reductions | High level of emission reductions | Few or no emission reductions |

A grid with or without ESS will have approximately the same emissions profile depending on the application of ESS and the technology chosen. The emissions profile may be higher if the ESS technology that is used is less efficient and has higher losses. The emissions profile could be lower because of renewable energy curtailment mitigation by using ESS.

Having more ESS does allow for a more flexible grid, and therefore allows for more renewable energy integration levels. As seen in places like Maui, where some renewable energy is facing curtailment situations with higher levels of integration, ESS allows for less "spilled wind". At higher renewable energy levels this grid flexibility becomes more important.

Alberta today has low levels of renewable energy integration and low levels of renewable energy curtailment overall. Alberta is moving towards 30 percent renewable energy integration by 2030; however, the analysis in Section 10.1 shows that there is some potential for curtailment and emissions reductions. This can be considered moving towards a medium-level of renewable energy integration.

The analysis of 2050 with 55 percent wind integration illustrates significantly higher curtailment and emission reduction potential compared to 2030, but is still a medium RE level.

Per the AESO's internal analysis, the increase in renewable energy on Alberta's grid by 2030 does not depend on storage technologies to enable further deployment. Similarly, the analysis in Section 10.1 indicates a limited potential for curtailment mitigation in 2030 due to transmission constraints but much greater curtailment potential in 2050.

More detailed modelling will be required in the future to more accurately identify curtailment mitigation potential especially as more is known about generation mix and transmission network structure. Section 10.1 indicates a limited potential for curtailment mitigation in 2030 due to transmission constraints but much greater curtailment potential in 2050.

On-grid or load located ESS facilities will not be able to easily demonstrate direct emission reductions since the benefit of the ESS is applied across multiple wind farms in the region. It may be reasonable for a policy to be enacted that enables ESS to monetize the system-wide levels of reduced curtailment.

There are parts of the AIES that historically have experienced transmission congestion resulting in renewable energy curtailment. In 2014, the AESO indicated that in the "South Region" 3,000 MWh of generation was constrained[62]. This is likely a result of either transmission congestion, supply surplus, or ramp rate limitations. As renewable development continues, Solas expects higher levels of transmission constraints and greater opportunities for ESS.

Curtailment due to ramping and supply surplus depends on the remaining generation portfolio's flexibility. Solas' literature review indicates that many jurisdictions have the potential to integrate up to approximately 40 percent VG by energy. However, this highly depends on grid flexibility. The analysis presented here is consistent with that view. Larger integration levels require greater levels of grid flexibility.

Quantifying what Alberta requires is subject to the ramping of load minus VG production profile, and the resulting ramping requirements. The AESO has now published rules for the connection and operation of grid-connected battery systems. Ideally, the AESO will have experience with several grid-connected ESS facilities before they become an essential component of the electricity system.

ESS will become more important in Alberta when there are issues associated with transmission congestion restricting or "spilling" RE production. Two other events will warrant ESS opportunities: RE production profiles create significant extreme ramping events resulting in RE curtailment; significant supply surplus events that warrant ESS opportunities. In addition, ESS will become more prevalent in periods of time characterised by higher electricity price volatility, or higher energy prices, or high delivery charges, or a combination of these environments.

[62] Constrained Down Generation, AESO, June 2015

The Canadian Solar Industry Association completed a study in May 2017 called the Alberta Market Outlook (2030) and this study also examined the potential requirement for extreme ramping events resulting in RE curtailment. This study indicated that there is a low likelihood of large sustained multi-hour ramping events. One case demonstrated a winter requirement of ramping capability increase to twice that seen in 2015 for one hour.

## 10.3 How does storage compare to other enabling solutions?

Integrating renewable energy into the grid requires multiple tools for the system operator. A summary of these tools is shown in Figure 20. These tools vary from decision support tools, smart grid and include ESS, ramping products, and local curtailment.

ESS assists in the integration of high volumes of renewable energy since it can provide a remedy to local curtailment issues, ramping products and demand response. Multiple other enablers can similarly support renewable energy integration such as natural gas peakers. Curtailment mitigation is likely the only situation where ESS is the sole solution or the sole temporary solution.

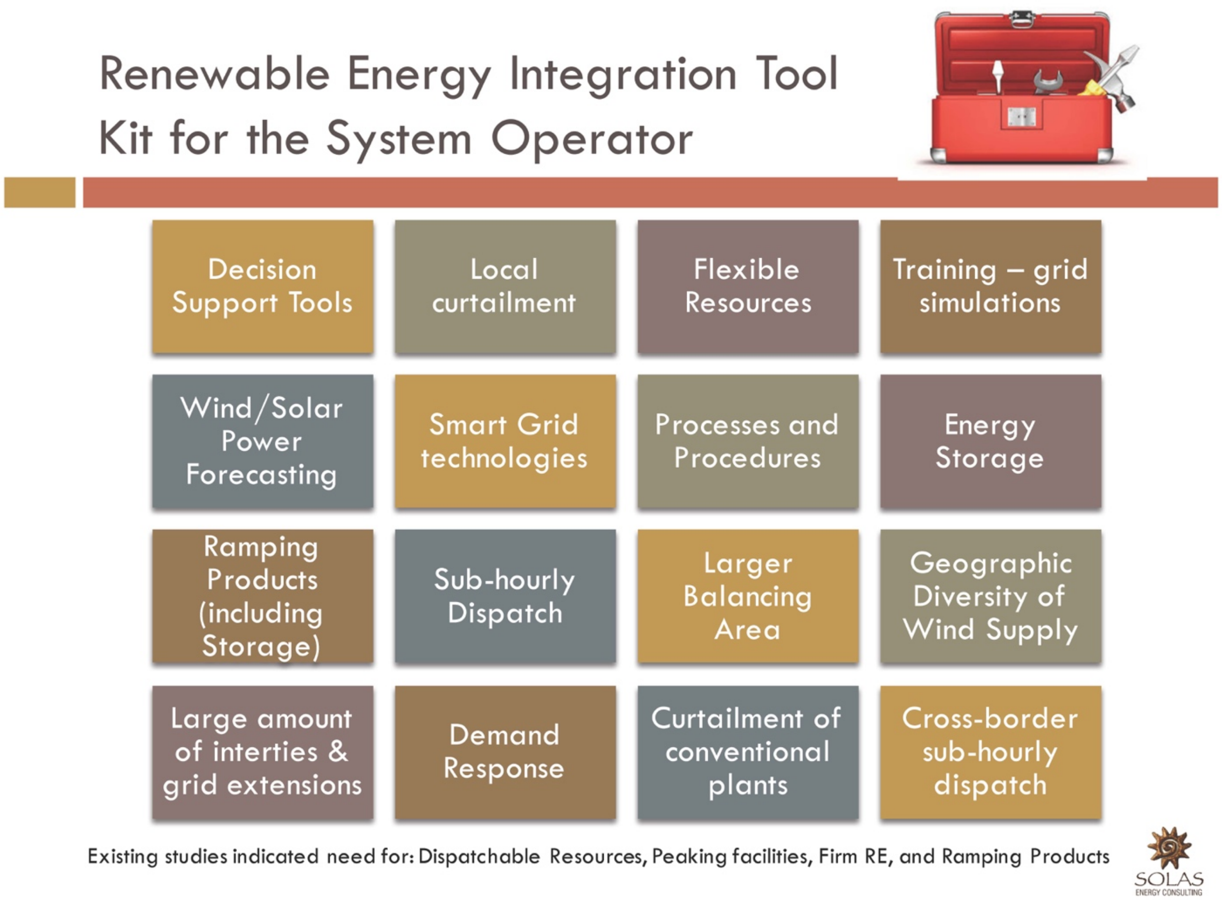



**Figure 20: Renewable Energy Integration Toolkit for the System Operator**

# 11 CONCLUSION AND NEXT STEPS

ESS has many technologies, multiple applications and can be applied at three different locations, on-grid, at generation or at load. The role of ESS will increase in importance in Alberta with the technological improvements in ESS, reduced costs, and the high integration of variable renewable energy generation. ESS can participate in the operating reserves market and will have a role along with additional gas fired generation for the mitigation of curtailment situations. The potential for renewable energy curtailment increases with additional deployment and can occur through either supply surplus, transmission congestion, and extreme ramping events.

GHG emission reductions can be directly generated by avoiding "spilling" renewable energy that would have otherwise been curtailed. Other applications of ESS in Alberta's high emissions intensity grid, create incremental GHG emissions. This results from losses between charging and discharging and the emissions intensity of this make-up energy. The Figure below identifies which applications, and locations create emissions, and which create emission reductions.

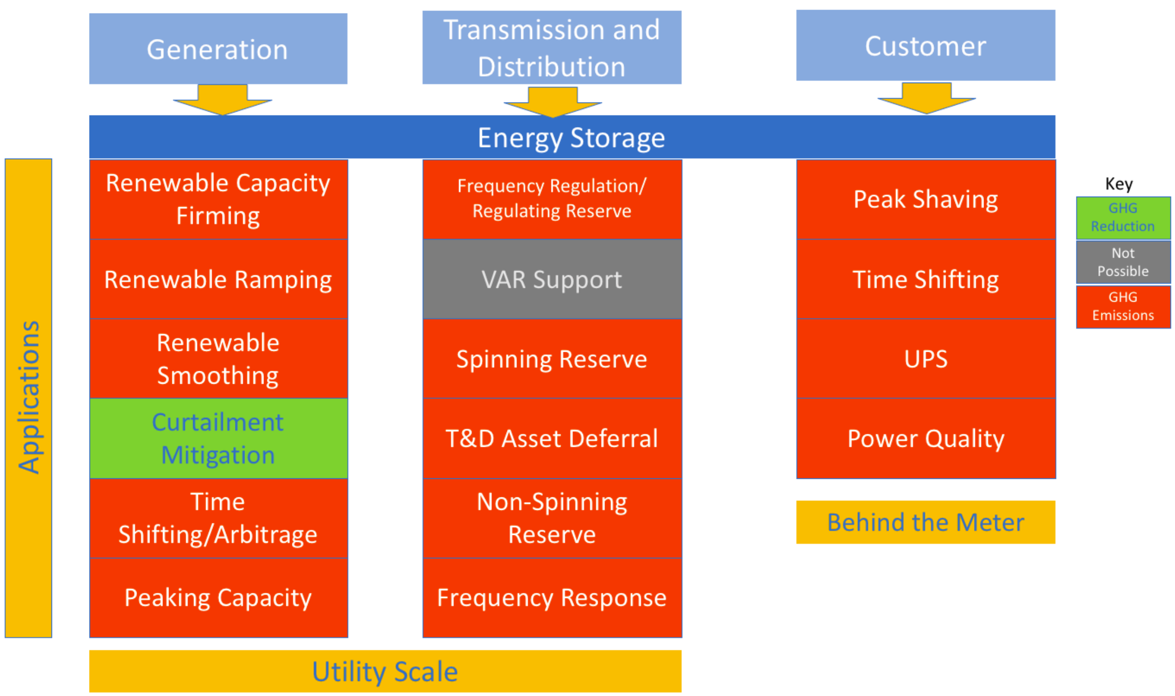



**Figure 21: Summary of Applications, Locations and Occurrences of GHG Emission Reductions in a Predominantly Thermal Grid** *(Red is creating emissions, Green is creating emission reductions)*

Alberta Innovates has a role to play in the advancement of ESS technologies to support the development of local expertise that will benefit the Alberta electricity market and can be exported to other jurisdictions. The Alberta government could modify the existing legislation and regulation to allow for ESS barriers to be reduced or removed. GHG protocols for emission reductions should be developed for ESS in Alberta. ESS has an opportunity to be of rising importance in the Electricity Sector within and beyond the Alberta borders.

1. ESS can provide many services. Often ESS is discussed solely within the context of energy arbitrage when in fact great project and system value can be delivered from other applications.

2. The paper presents a framework for evaluating the GHG emission reduction potential for ESS projects. The paper does not mean to present a draft protocol or to devalue other approaches, but fundamental principles are laid out here.

3. Changes are needed in the AESO rules to facilitate full participation in the energy and operating reserve markets. Rules need to be revised to achieve full value from storage. Storage can provide quicker more accurate regulating reserve and could be a cheaper alternative to transmission build in some cases.

4. An ESS project reduces GHG emissions when it is mitigating curtailment of renewable energy production. Other applications do not create GHG reductions.

5. The analysis completed here and in the Pan-Canadian Wind Integration Study shows increasing curtailment as wind integration increases, and storage can play the role of enabling renewable energy to avoid curtailment as the integration level increases.

6. In a very clean grid, storage will enable renewables through the reduction of curtailment;

7. Alberta based expertise in ESS can be of great benefit within and beyond the province.

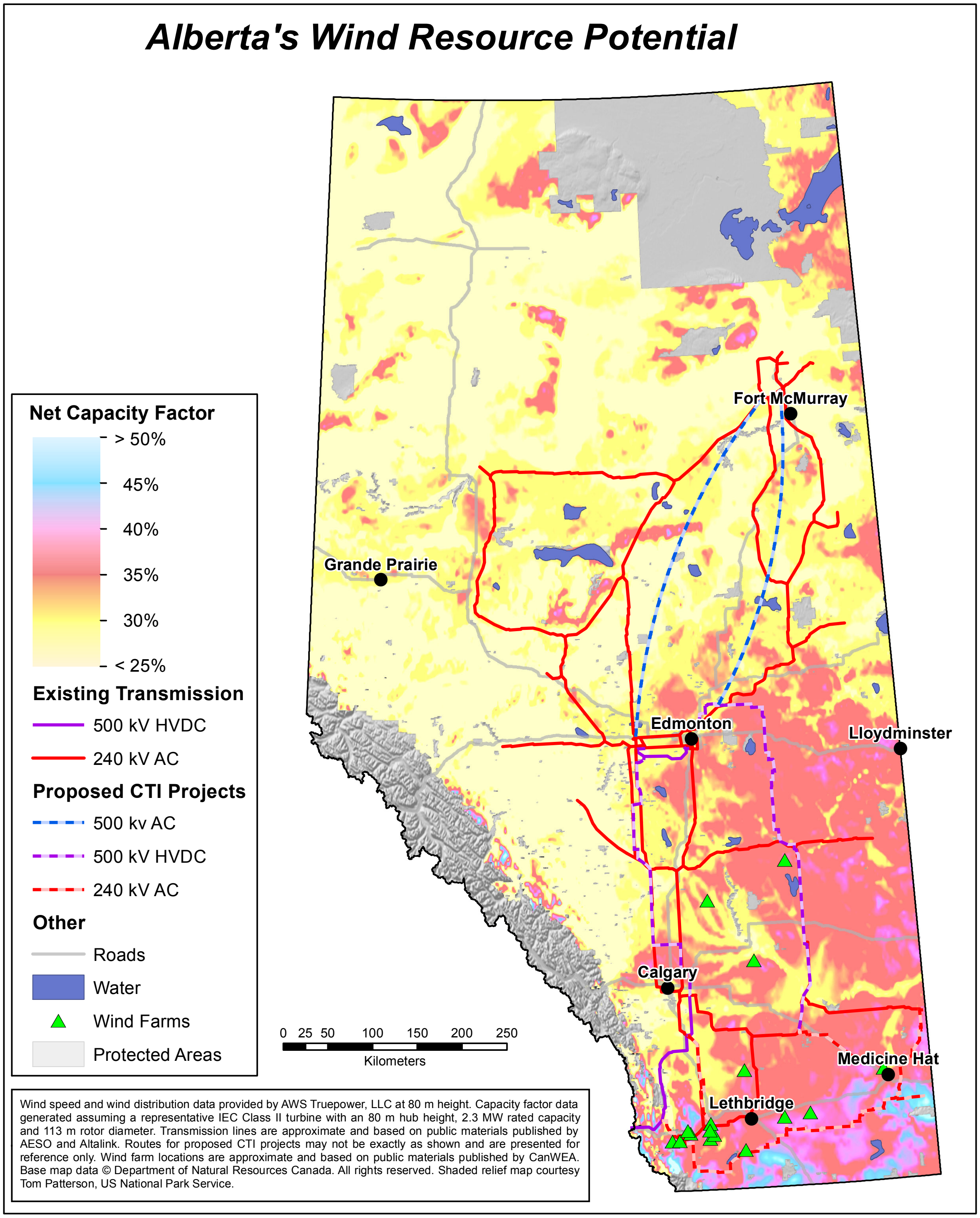
8. ESS is growing worldwide and Alberta's deregulated electricity market provides advantages in the deployment of ESS. This can lead to the development of intellectual capital associated with the use, deployment, and integration of ESS for multiple applications at the generator, on-grid and at load.

9. In the long term, the role for ESS in Alberta may be focused on RE curtailment mitigation, while short term applications may be associated primarily with operating reserves, UPS and power quality.

10. ESS provides a significant opportunity in the long-term to reduce emissions in the Alberta grid and enable larger scale integration of renewable energy.

Further study is required to understand the benefit of storage in reducing curtailment at different integration levels and generation mixes in more detail. ESS projects should be supported to develop expertise at the developer, owner and system operator levels so that immediate benefits can be recognised, understood and valued well in advance of the eventual high demand for ESS that may accompany increased levels of renewable energy integration.

## Appendix A-1 Alberta Wind Map



## Appendix A - 2 Alberta Solar Map