AUC
Alberta Utilities Commission

# Alberta Smart Grid Inquiry

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**The Alberta Utilities Commission**
Alberta Smart Grid Inquiry
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# Introduction

This is the report of the Alberta Utilities Commission (AUC or Commission) in response to Order-in-Council 93/2010 in which the Lieutenant Governor in Council requires the Commission to inquire into and report to the Minister of Energy on the Alberta Smart Grid.[1] The purpose of the Inquiry is to provide information to the Government of Alberta so that it can consider implementing policies supporting the deployment of smart grid technology in support of achieving the goals of Alberta's Provincial Energy Strategy.[2] Those goals are clean energy production, wise energy use and sustained economic prosperity.

The Commission's role is not to make policy recommendations. Rather, the Commission provides the government with information necessary to make informed policy decisions and in this report the Commission has provided a cost-benefit methodology to assist the government in assessing some policy options. The Commission opened a proceeding to solicit submissions from the industry and the public. Fifty-eight participants registered in the proceeding. Thirty-eight participants answered the 67 written questions posed by the Commission at the start of the proceeding. Nine participants replied to the submissions of others. In October 2010, 19 participants took part in the oral proceedings that occurred over two days in Calgary, and 10 participants appeared in the proceedings held in Edmonton.

The Inquiry process allowed interested stakeholders in Alberta's electricity industry to share their experiences and ideas with the Commission on a number of complex issues including the pace and timing for deploying smart technologies, approaches for conducting cost-benefit analyses, standards regarding interoperability and security, customer data privacy and access and other issues. This stakeholder input provided helpful information that has been incorporated into this report. In the end, the information accumulated from the Inquiry should enhance the identification of any required policies and the development of the approach needed to support the policy goals set out in Alberta's Provincial Energy Strategy while maximizing the benefits of a modernized electricity grid.

## What is smart grid?

Smart grid is a broad concept that describes the integration of hardware, software, computer monitoring and control technologies, and modern communications networks into an electricity grid. The attractiveness of the smart grid is its promise of helping electric utilities become more efficient and effective in operating generation, transmission and distribution networks, helping with the integration of more renewable and variable energy sources into the grid and empowering consumers with greater information and the capability to control their electricity consumption and costs.

In the Order-in-Council, the government characterized the smart grid as the modernization of Alberta's electricity system, through the application of advanced control and information technology, to meet the future needs of the province. The government stated that the characteristics of the smart grid include, but are not limited to:

[1] See Appendix 1 – Order-in-Council and Inquiry process.
[2] Exhibit 4.01, Alberta's Provincial Energy Strategy.

1. Inclusivity: The smart grid applies to the entire electricity system including generation, transmission, distribution, and customers.

2. Reliability: The smart grid provides enhanced ability to warn of and identify potential failures and take remedial action before users are affected, that is, the smart grid self-heals.

3. Security: The smart grid withstands cyber attacks.

4. Environmentally Friendly: The smart grid reduces the environmental impact of the Alberta electricity system through the application of advanced technology that will provide for the integration of more renewable generation, more effective load management, and better information for customers.

5. Accessibility: Electricity market participants must have access to all necessary information to make informed choices.

The Order-in-Council requested the Commission to inquire into and report to the Minister of Energy in relation to the following matters:

(i) the current status of smart grid development in Alberta

(ii) the status of smart grid deployment in other jurisdictions

(iii) the guiding principles, objectives and goals for developing the smart grid in Alberta

(iv) the enablers and barriers to the deployment and development of the smart grid

(v) the functionality requirements for the smart grid in Alberta, including standards such as those required for the interoperability in the exchange of information

(vi) the method of assessing costs and benefits of smart grid-related expenditures

(vii) the necessary courses of action to develop and implement the smart grid, including defining the roles for all the potential market participants

(viii) the regulatory approach to consider smart grid investments including the extent to which competitive markets can be relied upon to deliver the smart grid

(ix) other associated issues as required

Participants in the Inquiry addressed these characteristics and the matters upon which the Commission is to report. They emphasized that smart grid is not a static concept. Many of the participants in the Inquiry frequently made the point that most of what is referred to as smart grid is often the natural evolution of the grid and good engineering practice. They emphasized that smart grid continues to evolve as new technologies are developed and deployed and that evolution will be a complex, lengthy and transformative process that never ends.

The Commission also learned that while smart grid is a broad term, it does not describe a single complete and inextricably linked set of technologies. Instead, smart grid technologies are best assessed in each of the segments of the electricity system: smart generation, smart transmission,

smart distribution and smart meters[3] as well as smart technologies that can be employed in the retail segment and in the customers' premises. Each of these segments is made up of a number of elements. For example, there are multiple technologies that are smart transmission technologies, and different companies with different circumstances will choose to include different smart transmission technologies in their transmission systems. Furthermore, smart grid technologies can be deployed in each of these five segments independently of deployment in the other segments. It is not necessary, for example, to install smart meters in order to enjoy the benefits of smart transmission technologies. In some cases, however, the potential benefit of deploying a technology in one segment may be increased if other technologies are employed in other segments.

## Developments in other jurisdictions

A number of jurisdictions in North America have taken steps to begin the deployment of smart grid technologies. The Commission provides a summary of activities in various jurisdictions in Appendix 4 – Status of smart grid deployment in other jurisdictions.

In North America, the principal benefits of smart grid technologies most often cited include the potential for the reduction of greenhouse gas emissions,[4] economic stimulus and job creation, improved infrastructure reliability and security, increased efficiency of the electricity system through asset optimization and opportunities for customers to better manage their electricity consumption.[5] Depending on how smart grid is rolled-out, the costs could be substantial, and some or most of these costs would have to be recovered from customers. In addition, depending on the speed with which smart grid is rolled out, customers could find themselves paying for new technology while they are still paying to allow the utility companies to recover the costs of the old technology; in some cases the new technology might have to be replaced by even newer technology before the costs of the first two technologies have been recovered.[6] Furthermore, there have been controversies in other jurisdictions regarding the deployment of smart metering technologies. In California and Texas, residential customers blamed the new metering devices for overstating consumption. Independent reviews found that many of the reported problems were the result of poor implementation and customer communication and not caused by the technology itself. The result of these experiences is that many participants urged the government to "go slow" with any mandated roll-out of smart grid.

The cost and implementation difficulties associated with smart grid technologies have caused some regulators now to proceed with more caution. In Colorado, Oklahoma and Maryland, for instance, potential cost overruns and insufficient information regarding the expected benefits resulting from the implementation of smart transmission and smart distribution technologies and smart metering prompted the regulators to proceed cautiously with approvals or to reject the cost recovery mechanisms proposed by the utilities. In these jurisdictions, the regulators took measured and deliberate approaches in approving the utilities' deployment plans. Specifically, the regulators placed a cap on the amount collected from customers through rates, established a

[3] While meters are typically considered to be part of the distribution system, this report considers meters separately because some smart distribution technologies are not related to the meter.

[4] Mandated renewable portfolio standards are being implemented in states such as California, Colorado, North Carolina, Pennsylvania, and Massachusetts. See Appendix 4 – Status of smart grid deployment in other jurisdictions.

[5] Demand response programs have been implemented in states such as Florida and New York. Texas implemented smart grid policies and deployed smart grid as a means to promote retail competition.

[6] Transcript, Volume 2, pages 318-322.

guaranteed savings amount that was reflected in the customers' rates or instructed the utility to demonstrate the benefits after the technology was deployed and in use.

A number of jurisdictions have recently initiated smart grid inquiries prior to mandating any smart grid technology adoption because the potential benefits from implementing smart grid technologies may be limited and the costs of achieving them may be relatively high. It is such an examination of the various aspects of implementing smart grid technologies in Alberta that this Inquiry addresses.

## Smart grid in Alberta

This report addresses smart grid deployment in Alberta. While experiences in other jurisdictions are instructive, not all jurisdictions are the same and not all smart grid investments will be useful for the companies' operations or be beneficial to customers. The desirability of various smart grid technologies and the ability to realize potential benefits may be affected by whether the electricity industry is characterized by vertically integrated companies or, as in Alberta, by disaggregated industry segments with competitive generation companies and competitive retailers. Participants in the Inquiry emphasized that the desirability of any particular smart grid technology also depends on the unique circumstances of the company and its operating territory.

In Alberta, the restructuring of the electricity market and the introduction of competition in the generation segment, created the need for the introduction of an independent system operator to coordinate planning and operation of the transmission system and operation of the power pool. This system operator function is carried out by the Alberta Electric System Operator (AESO). Restructuring has had the effect of prompting considerable investment in wind generation and other renewable generation sources. In this environment, generation companies have incentives to deploy smart generation technologies to compete in the market and the AESO and transmission facility owners (TFOs) have deployed smart technologies to allow these new generation technologies to participate in the market. The competitive market structure for generation has resulted in significant investments in and deployments of renewable energy sources and smart transmission technologies.

In the distribution system, technologies such as distribution automation, outage management systems, and geographic information systems have been widely deployed for some time in response to changes in industry engineering practices. In Alberta, these technologies are being enhanced and upgraded with advances in computer and communications technologies that can be characterized as smart grid.[7] In addition, distribution entities (along with the AESO and retailers) have invested in billing, settlement and data storage systems, and the electronic communications systems required to support their role in the functioning of the competitive retail and generation markets.

[7] Exhibit 69.01, Cities of Red Deer and Lethbridge, Response to Commission Question 12: "Both upgrade programs were motivated by best utility practices, although both technologies may not be considered a 'smart grid' technology." A number of participants emphasized that many of the operations systems they have in place are continuously being upgraded on the basis of good engineering and business practices and only recently has the expression "smart grid" been applied to these activities.

Smart meters[8] are widely deployed for industrial and large commercial customers who consume approximately 70 per cent[9] of the electrical energy in Alberta. This number is increasing as smart meters are being deployed to progressively smaller commercial customers.[10] Many of these customers regularly adjust their consumption in response to prices in the power pool. Smart meters for residential and small commercial users have yet to be rolled-out to much of Alberta. The presence of a large industrial and commercial customer base with smart meters that responds to changes in the Alberta power pool price, and development of the billing and settlement systems to make the competitive generation and retail markets function smoothly, has required the development of an information and electronic communications infrastructure between the distribution companies, the AESO and competitive retailers. This information and electronic communications infrastructure could be enhanced to accommodate the introduction of smart meters for residential and small commercial customers.[11]

The retail market for electricity is competitive and participants in this market have already rolled out the electronic communications systems necessary to exchange information with the AESO and the distribution companies. This information and electronic communications infrastructure could also be enhanced to accommodate the introduction of smart meters for residential and small commercial customers.

This background is explained in greater detail in the report so that the policy considerations for the rollout of smart grid technologies in each segment of the electricity market can be considered in the Alberta context.

## Principles and objectives

The Order-in-Council asked the AUC to gather information with respect to the guiding principles, objectives and goals for the Alberta smart grid. The Commission invited participants to provide what they considered should be the principles and objectives of smart grid in Alberta. Most participants responded that they supported the provincial government's goals of clean energy production, wise energy use and sustained economic prosperity and were prepared to develop and implement programs in response to government mandates in order to achieve specific outcomes the provincial government might specify to help achieve these goals. The objectives most often mentioned were: reduction in $CO_2$ emissions, more efficient operation of the electrical system including reducing peak demand, more efficient use of electrical energy by customers and increased customer choice. No consensus emerged.

Five principles for the development of smart grid policies emerged:

1. Smart grid policies and objectives should be clear, well defined, and articulated prior to smart grid investments being mandated.

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8 Smart meters are meters that have embedded in them electronic communications devices capable of sending and receiving information, have the ability to facilitate various operational improvements for the distribution entity and provide usage information in real-time or over a variety of time periods.

9 A precise number is not available. This number is estimated using Figure 7 from Appendix 2 – Overview of the Alberta electricity market, and omitting the industrial on-site consumption.

10 ENMAX Power Corporation and EPCOR Distribution & Transmission Inc. install interval meters on sites where the customer's demand is above 150 kVA. ATCO Electric Ltd. and FortisAlberta Inc. install interval meters to customers with demand above 500 kW and 333 kW, respectively.

11 See Appendix 7 – Smart metering technologies and related matters, for more information.

2. Smart grid policies should maintain and enhance the reliability and quality of electricity service in Alberta.

3. Smart grid policies should support the operation and continuation of the competitive generation and retail markets and should not create artificial competitive advantages for one group of market participants over another.

4. Smart grid investments should be required to pass a cost-benefit test to protect customers from unnecessary rate increases.

5. Competitive market forces should be relied upon to the greatest extent possible to implement smart grid technologies in Alberta.

The Commission has prepared this report with these principles in mind, recognizing the progress made in Alberta as a result of the restructuring of the electricity market and the introduction of competition in the generation and retail segments of the industry.

### Structure of the report

The report begins with a description of the generation segment of the electricity industry in Alberta including its composition, the way in which the competitive power pool operates and the existing and potential smart grid applications for the integration of wind energy, distributed generation, micro-grids and micro-generation. The report then discusses smart transmission, smart distribution, smart meters and the retail and customer applications of smart grid technologies and their existing and potential deployment in Alberta. Each section concludes with a discussion of policy and regulatory considerations. Following this, the Commission briefly discusses communications, cyber security, standards and privacy issues related to smart grid in Alberta.

A series of appendices is included to provide more information about the Alberta electricity system, the current state of smart grid implementation in Alberta and an overview of smart grid developments in selected jurisdictions. The appendices also include a methodology for conducting a cost-benefit study to assist in assessing the potential benefits of a mandated roll-out of smart meters and the communications, billing and settlement, and data storage systems required to take advantage of the smart meter capabilities. Separate appendices describe smart technologies in use at the generation, transmission and distribution levels as well as specific smart meter technologies.

## Generation

### Types of generation

Generation facilities in Alberta are not subject to economic regulation. Rather, a competitive market for generation has been established and has operated since 1996. This competitive market structure is managed to accommodate all types of generation and to incent investors to build and operate their generation plants in the most efficient way to provide reliable, adequate and economical electricity for customers. This market structure provides a mechanism, called the power pool, for generators, importers, exporters and retailers to trade (buy and sell) electricity.

There is approximately 13,000 megawatts (MW)[12] of installed generation capacity on the Alberta Interconnected Electric System (AIES) including four main types of generation: coal-fired, natural gas-fired, hydro, wind and other renewable energy sources. Coal is the largest source of electric generation, accounting for approximately 46 per cent of installed capacity and roughly 59 per cent of total electrical energy produced in 2010. Natural gas-fired generation accounted for another 35 per cent of the total electricity production in 2010 while hydro and wind generation supplied just over two per cent each. A summary of the current installed capacity, electricity production by fuel source and annual utilization factors for the various types of generation in Alberta is provided in Appendix 2 – Overview of the Alberta electricity market, Figures 1, 2, and 3.

Coal's dominance in the production of electrical energy is due to coal being an abundant and extremely low-cost fuel source. In fact, a provincial policy adopted in the early 1970s which favoured coal as the fuel to be used to generate electricity ensured coal's dominance.[13]

Coal-fired generating units are base-load plants in Alberta that typically run at all times throughout the year due to their low operating costs. The average age of the coal-fired generating units in Alberta is about 28 years, and both planned and unplanned maintenance of these units tend to increase as the units age. In addition to providing electrical energy to the power pool, coal-fired generating units also provide a large portion of the operating reserves[14] which are required to maintain reliable operation of the AIES. Coal-fired generating plants inherently have limited operating flexibility because it can take several hours to start a unit and once operating, these units have limited ability to quickly adjust their output.

The restructuring of the Alberta electricity market introduced competition at the generation and retail segments of the market. Now, decisions to build generation plants are made by investors. This shift in decision making from regulatory authorities to market participants favoured the construction of lower cost, more efficient and environmentally clean technologies such as natural gas-fired generation. Consequently, the share of total production by coal-fired plants in Alberta has been gradually declining, largely due to increases in natural gas-fired production.

Natural gas-fired plants can range in size from large-scale generation plants (hundreds of MWs) to small-scale microturbines (less than one MW) and can be constructed in a shorter timeframe than coal-fired plants. Natural gas-fired generation in Alberta generally consists of two types: peaking and cogeneration.[15] Peaking units are dispatched by the AESO during periods of high electricity demand and also provide reliability or ancillary services to the AESO to maintain the reliability of the AIES.[16]

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12 ERCB ST98-2010, "Alberta's Energy Reserves 2009 and Supply/Demand Outlook 2010-2019" (2010) page 9-7, online: The Energy Resources Conservation Board, http://www.ercb.ca/docs/products/STs/st98_current.pdf.

13 ERCB Report 73-C, "Report on Choices among Energy Resources for Generation of Electric Energy in Alberta" (April 1973).

14 The Alberta Electric System Operator, "Operating Reserves", online: AESO, http://www.aeso.ca/gridoperations/19607.html.

15 Cogeneration is the simultaneous production of electricity and heat using a single fuel source.

16 The *Electric Utilities Act* defines ancillary services those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. [Section 1(1)(b)].

Approximately 70 per cent of the natural gas-fired capacity in Alberta is made up of cogeneration units. The market structure along with government policy and legislation facilitated the development of cogeneration facilities for large industrial customers. Cogeneration is predominant in the forestry, pulp and paper industries as well as the oil sands sector of the energy industry. In the oil sands sector, cogeneration is incorporated into integrated mining, extraction and upgrading projects, because of the need for both electricity and thermal energy. In Alberta, a significant portion of the cogeneration's electric power output is typically not available for use in the power pool because the primary purpose of cogeneration is to produce thermal energy and electricity for use in an industrial process. Any electricity provided to the power pool by cogeneration units is generally that which is in excess of the industrial process requirements.[17]

Hydroelectricity production in Alberta is dependent upon rain and snowfall because these units are run-of-river with generally very little storage capacity. The hydro units in Alberta can only produce a limited amount of electricity due to their small reservoir size. However, these plants have very flexible operational characteristics such as the ability to increase and decrease output very quickly or to be immediately started or stopped, which makes them active participants in the ancillary services and operating reserves market.[18]

More recently, there has been strong interest in wind generation development in Alberta. The amount of installed wind generation capacity now totals approximately 780 MW.[19] Rapid technological improvements in wind generation have allowed wind generators to compete in Alberta's electricity market due to lower capital costs and shorter construction times. In addition, due to their positive environmental attributes, wind generation operators have been able to obtain additional revenue either from federally funded wind credit programs or by selling carbon credits. While wind generation currently makes up a relatively minor proportion of the installed capacity in Alberta, it is expected that up to 1,300 MW will be connected to the AIES by the end of 2011.[20]

The amount of base-load generation in the power pool can vary hourly and range between 4,500 MW and 6,000 MW[21] throughout the year. Base-load generation includes output from coal-fired, natural gas-fired or hydro units that is either offered into the power pool at zero dollars (to ensure continuous operation), from generators that are required to produce a certain output to support the AIES, or from cogeneration units on an industrial customer's site.

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17 ERCB ST98-2010, "Alberta's Energy Reserves 2009 and Supply/Demand Outlook 2010-2019" (2010) page 9-7, online: The Energy Resources Conservation Board, http://www.ercb.ca/docs/products/STs/st98_current.pdf. Natural gas cogeneration plants dedicated to the oil sands sector generated 14,613 GWh of electricity in 2009, of which 9,649 GWh (66 per cent) was used on site, with the remaining sold into the power pool.

18 See Appendix 2 – Overview of the Alberta electricity market.

19 The Alberta Electric System Operator, "Current Supply and Demand" (January 24, 2011), online: AESO, Market and System Reporting, http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet.

20 K. Gunsch (prepared by K. Aksomitis), "Phase Two Wind Integration Study" (December 16, 2010), online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/Wind_Integration_Discussion_Paper_-_Phase_Two.pdf.

21 The Alberta Electric System Operator, "Wind Power Operational and Market Report Week of Dec 12, 2010 to Dec 8, 2010" (December 22, 2010), online: AESO,http://www.aeso.ca/downloads/Weekly_Wind_Report_Dec_12_to_18_Dec.pdf.

Micro-generation has also been introduced in Alberta. The *Micro-generation Regulation*[22] allows qualified customers to install micro-generation (for example, solar panels and small wind generators with a generating capacity of less than one megawatt) for the purpose of generating electricity for their own use and to receive a credit for any excess electrical energy that flows into the distribution system. Distributed generation, micro-generation and micro-grids are discussed further in Appendix 2 – Overview of the Alberta electricity market.

The interconnected electrical system operates as a single integrated system and electricity produced by generators is pooled to meet the total customer demand for electricity at any instant. The amount of electricity generated and consumed must be continuously and instantaneously balanced because there are few effective means to store electricity. All elements of the electrical system from power plant to transmission and distribution lines to household appliances must be synchronized within a narrow band of tolerances. Deviations from this instantaneous balancing will affect the operation of the entire system and may damage equipment or result in a system-wide blackout. Therefore, the AESO must continuously balance the amount of electricity entering the AIES with the amount of electricity consumed.

### Competitive market structure

The way in which electricity is provided to customers in Alberta has changed fundamentally over the last two decades through industry restructuring, which was designed to introduce competition into the electricity industry. Prior to market restructuring, electricity was generally provided by vertically integrated electric utilities that directly served their customers and owned their own generation, transmission and distribution facilities. Restructuring separated generation, transmission, distribution and retailing in order to introduce competition into the generation and retailing segments of the industry. At the same time, independent agencies were established to coordinate the planning and operation of the transmission system and the sale of generated electricity.[23] Under this market structure, generation is owned and operated by private, non-regulated companies and the price of electricity is set in the power pool.

The Independent System Operator (fulfilled by the AESO),[24] is a statutory, not-for-profit corporation established under the *Electric Utilities Act*[25] and is responsible for operating the power pool in Alberta. The AESO is required to operate the power pool in a manner that is fair, efficient and open to all market participants exchanging or wishing to exchange electric energy through the power pool and that gives all market participants a reasonable opportunity to do so.[26]

The Alberta market uses a single hourly price to determine the price that each generator is paid for the electricity produced during the hour, and the price that each customer buying from the power pool is required to pay for electrical energy consumed. The Alberta electricity market is defined as a real-time, energy only market meaning that the owners of generating plants receive

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22 A.R. 27/2008.

23 At that time there were two separate entities created to perform this role: the Transmission Administrator oversaw the planning and operation of the AIES, and the Power Pool of Alberta oversaw the trading (buying and selling) of electrical energy.

24 The Transmission Administrator and the Power Pool of Alberta were combined in 2003 as a result of changes to the *Electric Utilities Act* to become the Independent System Operator (Alberta Electric System Operator or AESO.)

25 S.A. 2003, Ch. E-5.1

26 *Electric Utilities Act*, Section 18(1).

payment for the actual amount of electrical energy produced (rather than for the availability of their generating capacity) at a price known only at the instant of consumption.

Consequently, the generators are at risk for having to rely on the hourly pool price to recover their operating and capital costs as well as to earn a return on their investment. The hourly pool price is the only price signal available in the Alberta market to incent the construction of new generation facilities. Generators and large industrial and commercial customers respectively may also offer their generation capacity or the ability to curtail consumption to the AESO as ancillary services or into an operating reserves market which is operated by the AESO to ensure that generation and consumption are continuously and instantaneously balanced.

Demand response[27] is a necessary part of a functioning electricity market. Currently, large industrial customers can respond to a price signal in the power pool and reduce their consumption. There are industrial and large commercial customers who can voluntarily curtail between 175 and 300 MW of consumption (commonly referred to as load) in response to high power pool prices.[28] This participation is made possible by existing smart metering technology, in the form of interval meters installed at industrial and large commercial customers' sites, that record consumption on a fifteen-minute interval basis.

The AESO requires that price responsive customers with electricity demand above certain sizes provide notification of the circumstances under which they will reduce their consumption so that the AESO is aware of when any potential large changes in consumption may occur. Large industrial and commercial customers are allowed to bid their consumption into the power pool (a reduction in consumption can be a substitute for an increase in generation) however in practice they rarely elect to do so.[29] The AESO is continuing to explore opportunities to increase large industrial and commercial customer demand participation in the power pool.[30]

In November 2010, the AESO issued a request for expressions of interest to provide up to 485 MW of load shedding service. Under the service, providers will be compensated under a three part payment structure similar to the current standby operating reserves program. The AESO received responses from potential providers amounting to a total of between 700 MW and 800 MW of potential load shedding capacity. As a result of the favourable amount of responses, the AESO is continuing along with the procurement process to identify the list of providers.[31]

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[27] Demand response refers to changes in electrical energy usage by customers in response to incentive payments designed to induce lower electricity use at times of high power pool prices or when system reliability is jeopardized.

[28] J. Mossing, S. Heidt, "AESO 24 Month Reliability Outlook Presentation" (January 19, 2010), The Alberta Electric System Operator, page 5.

[29] The Market Surveillance Administrator, "Alberta Wholesale Electricity Market" (September 29, 2010), online: MSA, http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf.

[30] Exhibit 103.01, AESO Response to Commission Question 2.

[31] The Alberta Electric System Operator, "RE: AESO Request for Expression of Interest in LSSi" (January 18, 2010), online: AESO http://www.aeso.ca/downloads/LSSi_Release_Jan_18_2011.pdf.

## Wind integration

The integration of wind generation into the AIES presents certain challenges from an operational and power pool perspective due to its variable nature and the need to maintain reliable operation of the AIES. The output from wind generators occurs where and when[32] weather conditions permit. The output from a wind generator may increase or decrease rapidly; output may occur when the demand for electricity is low (in the middle of the night) or may be minimal or none during critical or high-consumption periods. Wind generators typically have different electrical characteristics compared to conventional generation including the manner in which system voltages are supported and the manner in which wind generators respond to transmission and generation outages on the AIES. The AESO has proposed changes to its rules[33] and also expects to make use of smart grid technologies, controls and approaches on the transmission system to address some of these differences in generation characteristics.[34] Given that a large proportion of Alberta's installed generation operates as base-load generation and is relatively inflexible from an operational perspective, smart grid technologies and other sophisticated approaches are being employed by the AESO to accommodate the large-scale integration of wind generation.

Wind generation, given its variable output, must be backed up by resources that the AESO can dispatch or control in order to keep the supply and demand of electricity in continuous balance on the AIES. These backup resources may include generation capacity, exchanges of electricity with neighbouring jurisdictions through transmission interconnections, or curtailment of industrial or large commercial customer consumption as required by the AESO. When wind-generated electricity is available, its output is accepted into the AIES and the AESO directs other generation sources (coal-fired, hydro and natural gas-fired generators) to decrease their output. When the amount of wind-generated electricity is decreasing, the AESO directs other generators to increase their output. The AESO may also call upon customers who have contracted with the AESO to reduce consumption in order to offset the reduction in wind generation.

The deployment of intelligent controls, computer applications, communications and smart grid technologies is considered to be a key enabler to the large-scale integration of renewable generation, including wind. These technologies will facilitate the interconnection of renewable energy generators across a wide geographic area, management of distributed generation resources, the integration of new energy storage technologies, the use of customer load as a balancing resource and the enhancement of corrective capabilities when problems occur.

## Current deployment of smart generation technologies

The AESO currently has a number of initiatives underway to accommodate the large-scale integration of wind generation into the AIES and power pool in a reliable, fair, efficient and openly competitive manner.[35] These efforts have spanned several years and include the

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32 On an annual basis, the wind generation capacity factor in Alberta is 30 to 35 per cent. There are, however, times of the year (typically spring and fall) when the capacity factors of wind generation can approach 60 to 70 per cent and periods when there is no wind generation output on the system due to prevailing weather conditions (no wind, too much wind, or extremely low temperatures).

33 ISO Rule Section 502.1 – Wind Aggregated Generating Facilities Technical Requirements, section 18, online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/2010-08-10_Wind_Technical_Rule_FINAL_CLEAN.pdf. This proposed rule is currently the subject of AUC Proceeding ID No. 787.

34 Exhibit 103.01, AESO Response to Commission Question 1.

35 Exhibit 103.01, AESO Response to Commission Question 2.

development of predictive tools such as wind forecasting,[36] on-site wind power management applications such as power and ramp rate limiting, enhanced supervisory control and data acquisition (SCADA), rules,[37] communications networks between the wind generating facilities and the AESO's control centre and decision support systems for the AESO.[38] Some of these technologies are discussed further in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

The AESO also indicated that it may consider using the control capabilities of high-voltage direct-current technologies and advanced power electronics on the transmission system to provide greater flexibility to accommodate the variability of wind generation.[39] These technologies are considered to be smart technologies and their application in the transmission system is discussed in the Transmission section of this report.

### Future considerations

The AESO considers that integration of more renewable generation will also be supported by refining and developing new market rules and business processes and is therefore exploring several longer-term refinements to its rules and practices. This includes a review of the necessary amount and type of balancing resources and upgrades to energy scheduling practices with neighbouring jurisdictions to allow sharing of balancing resources and obligations between regions.[40]

The AESO is also considering the use of demand response programs as a balancing resource where technically feasible.[41] Independent system operators across North America are making increased use of demand response programs to meet a portion of their balancing and operating reserve requirements. These programs can be very responsive (available in seconds or minutes) and helpful in balancing the variability of renewable generation such as wind. The Commission heard in the Inquiry that the introduction of new demand response programs could support the integration of wind and maintain the reliability of the AIES. These programs would be attractive to large industrial and commercial customers if they can be structured as an ancillary service provided to the AESO in which the customers are financially compensated for curtailing their consumption.[42] In the Inquiry, industrial customers suggested that new demand side options

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36 In January 2010, the AESO contracted with a third party forecaster to provide a centralized wind power forecast for Alberta. [AESO, "Wind Power Forecasting Services", online: The Alberta Electric System Operator, http://www.aeso.ca/gridoperations/18286.html].

37 In August 2010, the AESO proposed rules that will apply to wind generating facilities including provisions for wind power forecasting, ramp rate and power limiting, frequency control and installation of phasor measurement units. [ISO Rule Section 502.1 – Wind Aggregated Generating Facilities Technical Requirements, section 18, online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/2010-08-10_Wind_Technical_Rule_FINAL_CLEAN.pdf.]

38 The AESO has developed and continues to refine decision support systems that provide information regarding wind forecasts and AIES ramping capability in operating displays.

39 Exhibit 103.01, AESO Response to Commission Question 1.

40 Exhibit 103.01, AESO Response to Commission Question 2.

41 Transcript, Volume 1, page 29.

42 For example, the system operator in Texas curtailed 1100 MW of industrial load in February 2008 to avoid a major system disturbance. The unexpected loss of wind generation coincident with an unanticipated load increase and the unavailability of conventional generation prompted the system operator to call upon the industrial load to curtail their load and assist in balancing the system.

would further support wind integration and system reliability without the need for additional smart grid technology.[43]

Future implementation of smart metering technologies on a large scale (or other means of direct load control) could allow the aggregation of electricity consumption of residential and small commercial customers to provide reliability services to the AESO. This would require that customers agree to reduce their consumption when the AESO needs to balance the system. It is not known how many residential customers might choose to participate in these programs if offered. Participation in such a program could place obligations and duties on a customer to reduce consumption when called upon and require the need for supporting systems and equipment such as smart meters and load control devices to verify compliance. Pricing schemes to compensate customers could be developed and marketed by aggregators.

Energy storage also has the potential to assist in addressing the challenges associated with the large-scale integration of variable generation such as wind. In many regions of North America, rapid installation of wind power has created overgeneration where high winds at night during times of low demand create more electrical energy than is needed on the system. Energy storage technologies have the potential to store and deliver this excess electrical energy when it is needed during peak demand conditions. Energy storage technologies may also be used to balance the variability of wind generation and help to avoid curtailing or limiting the amount of wind generation that is delivered onto the grid. Storage devices can typically respond very rapidly to changes in the system conditions brought about by variable generation. When used with high-speed communications systems and control devices, energy storage technologies can provide ancillary services such as spinning reserve, frequency and voltage regulation, black start[44] services and other applications. Different forms of energy storage are discussed in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

The commercial and operational viability of energy storage systems for the integration of renewable energy sources is being tested through pilot projects and demonstration projects in other jurisdictions.[45] The state of California recently passed a bill that requires utilities to install energy storage systems.[46] At this time, no specific programs or initiatives to investigate or integrate energy storage technologies into the AIES or power pool have been initiated in Alberta. The AESO stated that it will develop the necessary technical interconnection standards[47] to connect storage technologies to the transmission system. It is also expected that the AESO will monitor pilot projects and demonstration projects in other jurisdictions to assess the applicability of introducing advanced storage technologies into the power pool and real-time operations.

The Commission heard from a number of participants in the Inquiry that there are numerous industry groups, research organizations, universities and experts working on international initiatives to address the challenges associated with the large-scale integration of variable generation. Many of these organizations have multi-year programs and research projects to

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43 Transcript, Volume 1, pages 113 and 124.

44 Black start is the process of restoring a power station to operation without relying on external energy sources.

45 California ISO, "Participation of Limited Energy Storage Resources in CAISO Electricity Markets" (January 16, 2009), online: California ISO, http://www.caiso.com/2338/233810ac4147a0.pdf.

46 California State Assembly Bill 2514 requires Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric to have energy storage systems capable of supplying at least 2.25 per cent and five per cent of their system peak demands by 2015 and 2020 respectively.

47 Exhibit 103.01, AESO Response to Commission Question 27.

develop and demonstrate emerging technologies, implement new planning and operating practices and technical requirements, and are developing computer software to accommodate the large scale integration of variable generation.[48] The AESO is monitoring developments in other jurisdictions to assess the applicability of introducing similar approaches in Alberta.

### Distributed generation

Distributed generation is small-scale power generation connected to a distribution system providing electricity close to the point of consumption. For some customers, distributed generation promises lower costs, improved reliability, reduced emissions, or improved security of supply to critical services such as hospitals. There is very little distributed generation in Alberta and it does not have to participate in the power pool. The successful integration of a large amount of distributed generation located across the entire span of the AIES will require the intelligence, control and communications networks made possible by the deployment of smart grid technologies if distributed generation becomes larger and more widely deployed. The challenge will be in deploying the technology so that distributed generation is reliably and safely integrated into distribution system operations and becomes a controllable and dispatchable resource for the AIES.

In the Inquiry, the Commission heard that the AESO and transmission and distribution facility owners are not currently concerned about the impact on the system or market operations of generators connected to the distribution system. In the future, high levels of distributed variable generators (e.g., small solar or wind power) connected to the distribution system either individually or in aggregate across the system, could have an impact on the reliable operation of the AIES and the power pool. This generation may need to be treated in a similar manner to transmission-connected variable generation.[49]

### Policy considerations

Participants in the power pool already have sufficient incentives to employ smart technologies to make their operations as efficient as possible. The AESO has proposed that variable generators adopt smart technologies and controls[50] to deal with the unique characteristics of their generation type.

The government of Alberta's Provincial Energy Strategy supports responsible clean energy development and the promotion of the market for the consumption of renewable energy. There are no specific incentives for the development of renewable energy sources such as wind generation in Alberta. The power pool accommodates all types of generation and incents generators to build and operate their power plants in the most efficient way to provide reliable, adequate and economical electricity for customers. Emissions are regulated through the *Specified Gas Emitters Regulation*[51] and terms and conditions contained in AUC power plant approvals.

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48 The North American Electric Reliability Corporation, "Special Report: Accommodating High Levels of Variable Generation" (April 2009), online: NERC, http://www.nerc.com/files/IVGTF_Report_041609.pdf.

49 This may include compliance with AESO adopted reliability standards including provisions for power limiting, ramp rate limiting, frequency control and wind power forecasting.

50 ISO Rule Section 502.1 – Wind Aggregated Generating Facilities Technical Requirements, section 18, online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/2010-08-10_Wind_Technical_Rule_FINAL_CLEAN.pdf. This proposed rule is currently the subject of AUC Proceeding ID No. 787.

51 A.R. 139/2007.

The competitive market structure in Alberta has enabled the development of renewable resources.[52] In response to these developments, the AESO has implemented smart technologies to integrate wind and other renewable generation into the power pool. The AESO is also exploring several long-term refinements to its rules to accommodate large-scale integration of wind generation and other types of variable generation.[53]

The Commission heard that the power pool structure has supported the development of a relatively significant demand response program for large industrial and commercial customers in Alberta and there is the potential for the AESO to develop new demand-side options to back up wind generation and to support system reliability. Participants representing the interests of the competitive generation companies expressed concerns with the use of specific financial incentives to compensate customers for reducing consumption because those incentives could distort the competitive market.[54] For example, they indicated that any availability or capacity payment made available to some types of market participants and not others would amount to a subsidy and would create a non-level playing field.[55]In the Inquiry, the Commission heard that the current level of distributed variable generation is not a concern.[56] However, it is expected that the AESO will monitor the development of distributed generation and lead any industry efforts in Alberta to ensure that the reliability of the AIES and to ensure that the fair, efficient and openly competitive operation of the power pool is not compromised. An initiative to allow aggregators to pool the energy consumption of residential and small commercial customers having smart meters may require changes to existing rules and practices but there do not appear to be any major impediments in Alberta for aggregators to offer residential and small commercial customers the opportunity to participate in these types of programs.

In the Inquiry, AltaLink Management Ltd. (AltaLink) indicated that energy storage technologies could potentially provide benefits from the generation segment through transmission and distribution segments to the customer. AltaLink raised the question of whether energy storage devices would be treated as regulated assets or be allowed to freely compete in the power pool.[57] Energy storage is one of the emerging solutions for addressing the challenges associated with the large-scale integration of variable generation because it may provide a balancing resource to offset the intermittent nature of variable generation. There would appear to be no barriers to deployment of energy storage facilities as a non-regulated generation asset that could provide energy to the power pool and ancillary services to the AESO. Legislative or policy changes may be required to clarify whether energy storage technologies would be regulated as transmission or distribution assets or be left unregulated and deployed in the competitive generation market.

The AESO has sufficient rule-making powers to make ongoing refinements to its rules and practices to accommodate the large scale integration of wind generation, increase the participation of customers in the power pool or provide reliability services and introduce new

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52 For example see: J.Bell, T. Weis, "Greening the Grid, Powering Alberta's Future with Renewable Energy" (January 2009), page 10, online: The Pembina Institute, http://pubs.pembina.org/reports/greeningthegrid-report.pdf.

53 K. Gunsch (prepared by K. Aksomitis), "Phase Two Wind Integration Study" (December 16, 2010), online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/Wind_Integration_Discussion_Paper_-_Phase_Two.pdf.

54 Exhibit 87.01, IPPSA Response to Commission Question 50.

55 Exhibit 87.01, IPPSA Response to Commission Question 1.

56 Transcript, Volume 3, page 603.

57 Exhibit 99.02, AltaLink Response to Commission Question 53.

technologies (storage) or new entities (aggregators). The AESO has also implemented smart technologies to support its rules and practices and is exploring new technologies to assist in the integration of renewable energy resources. New policies may be required if barriers to achieving the goals of the Provincial Energy Strategy arise, but none appears to be necessary now.

## Transmission

### Transmission grid

The transmission system in Alberta is made up of approximately 25,000 kilometres of transmission lines that deliver electric energy generated from coal-fired, natural gas-fired, hydro, wind and other renewable generation sources to substations located near to where the electricity is consumed. The transmission system covers a wide geographic area and is an integrated system of 500-kilovolt (kV), 240-kV, 144-kV and 72-kV transmission lines and substations across Alberta and is owned and operated by seven different entities.[58] This network together with generation is referred to as the AIES. The transmission system was initially designed to transmit electricity from large centralized generation plants to homes, communities and businesses spread across great distances and did not contemplate the emergence of a competitive generation market or the large-scale integration of renewable generation.

Electricity market restructuring resulted in competition being introduced to the generation and retail segments of the market. Transmission, however, remains regulated by the AUC and the AESO to ensure just and reasonable rates, open non-discriminatory access and reliable service.

The AESO is responsible[59] for overall coordination of grid operations, for planning and arranging for upgrades to the transmission system, for providing open, non-discriminatory transmission access to all forms of generation, wherever they are located, and for operating a fair, efficient and openly competitive power pool in Alberta. The AESO is independent of any industry affiliations and owns no transmission, distribution or generation assets. The TFOs continue to manage the day-to-day operation and integrity of their transmission system and equipment. An overview of the Alberta market, participants and agencies is provided in Appendix 2 – Overview of Alberta electricity market.

The transmission system in the restructured electricity market in Alberta is subject to more transactions, participants, and greater variability in system conditions than in the past. The large-scale integration of variable generation such as wind, ongoing evolution of the market structure and the need to continue to operate the system reliably and efficiently over a wide area have added another layer of complexity to how the transmission system is planned and operated in Alberta. The transmission infrastructure is also aging, thus requiring more rigorous use of equipment diagnostics and creative approaches to extend the life of the transmission facilities or to upgrade or replace them when necessary.

[58] List of entities is provided in Appendix 2 – Overview of the Alberta electricity market. Suncor also owns and operates transmission lines and substations for their own use and have an Industrial System Designation classification.

[59] The Alberta Electric System Operator, “About AESO”, online: AESO, http://www.aeso.ca/ourcompany/ourCompany.html.

The implementation of advanced transmission technologies and approaches became necessary for the transmission system in order to accommodate and facilitate the requirements of the competitive generation market. More advanced technologies will be required as an increasing amount of variable generation resources (such as wind) become connected to the AIES. The AESO and the TFOs will be required to maintain system reliability across a wide range of load levels and generation output during normal daily conditions and also during adverse weather conditions and system outages. As a result, the AESO and the TFOs have incorporated a number of smart transmission technologies in Alberta's transmission system.

### Current deployment of smart transmission

The Commission asked the AESO and the TFOs to provide information regarding their activities and investments in smart transmission technologies. A summary is included in Appendix 3 – Current status of smart grid development in Alberta. The AESO and AltaLink have installed many devices that are considered to be smart transmission technologies such as phasor measurement units (PMUs), dynamic thermal line ratings (DTLR) technology, and Flexible AC Transmission (FACTS) on transmission projects. AltaLink has also upgraded the telecommunications systems in their substations to enhance its protection, control, automation, and monitoring systems. The smart transmission technologies, their expected benefits, how they have been implemented in Alberta and potential future applications are described in the following paragraphs.

Phasor measurement units are considered to be a smart transmission technology because they can provide a more complete, timely and accurate depiction of the operational status of the grid. These devices measure voltages and electrical currents at multiple locations up to 30 times a second across the grid.[60] The AESO and the TFOs deployed 27 PMUs across the AIES[61] and have been using the PMU data to investigate outages on the transmission system as well as to compare actual system operations with results from computer simulations. The costs of these investments are included in tariffs approved by the Commission.

Smart transmission technologies and automatic controls are being used to enhance the capability of the transmission system and reliability of the AIES by warning of and identifying potential failures or unstable conditions. Corrective action could then be taken before outages or disruptions occur. This is commonly referred to as self-healing. Special protection (or remedial action) schemes are commonly applied in Alberta by the AESO and the TFOs and throughout the industry.[62]

Sensor technologies are currently being employed by the TFOs to provide near real-time data on the status and condition of their equipment. For example, AltaLink installed gas monitoring devices on critical transformers and gas density monitors on certain circuit breakers. These sensors enable AltaLink to identify potential equipment failures and take action to repair or replace the equipment in a more cost-effective manner.[63]

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60 A SCADA system typically collects a single voltage and current value from a particular location every two to five seconds.

61 There are currently 27 phasor measurement units installed in Alberta while there are only 150 installed across North America.

62 Standards and practices have been established by the North American Electric Reliability Corporation (NERC) and there are over 70 special protection schemes currently in place on the AIES.

63 Exhibit 99.02, AltaLink Response to Commission Question 5.

As discussed in the Generation section of this report, the AESO has introduced new approaches, technical requirements and smart transmission technologies to enable the large-scale integration of renewable variable generation. These technologies include sophisticated information applications and systems, wind power management controls, advanced wind forecasting applications, dynamic thermal line rating devices and applications, PMUs and telecommunications infrastructure to manage the increasingly complex two-way flow of electrical energy and information.

The AESO and the TFOs make extensive use of communications technology including microwave networks, power-line carrier systems and fibre-optic links for SCADA systems and for teleprotection circuits.[64] New transmission projects will be equipped with a communications component that could be designed to accommodate future smart grid requirements.[65]

### Potential benefits of smart transmission technologies

Flexible AC Transmission Systems can be employed to enhance the reliability, security, capacity and efficiency of the power system. High-voltage direct-current (HVDC) technologies that use similar power system electronics have been deployed elsewhere for many years and are considered by many stakeholders to be a form of smart grid technology. Technologies such as FACTS and HVDC can also be used to contribute to a more efficient and flexible grid and make better use of transmission lines through control of line flows resulting in reduced line losses and more efficient use of generation output. The AESO also indicated that FACTS and HVDC transmission lines can also be used to support the integration of large-scale renewable generation on the grid and to accommodate distributed generation.[66]

The deployment of PMUs is expected to increase across North America. The PMU data can enable transmission lines and interconnections between neighbouring jurisdictions to be operated closer to their physical capacity (thermal) limits. The AESO is working with the Western Electricity Coordinating Council[67] to coordinate PMU integration and data exchange efforts that would enable PMU data from neighbouring jurisdictions to be routed to the AESO's control center.[68] Automatic controls that use data from PMUs can prevent large outages or assist in restoring the transmission system when an outage occurs. These efforts and further information on this smart transmission technology are provided in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

Dynamic thermal line rating and monitoring equipment are sensor devices placed on transmission lines that typically monitor the actual physical condition (line tension or line sag) of the lines. Dynamic thermal ratings are determined based on real-time measurements of actual

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64 Teleprotection includes the use of protective relays in conjunction with communication links to provide accelerated and selective isolation of faults on transmission lines, transformers, reactors and other critical transmission facilities.

65 Exhibit 103.01, AESO Response to Commission Question 2.

66 Exhibit 103.01, AESO Response to Commission Question 2.

67 The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. The Western Interconnection includes the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, portions of Montana, South Dakota, New Mexico and Texas in the United States, the Provinces of British Columbia and Alberta and a portion of Baja California in Mexico.

68 Exhibit 103.01, AESO Response to Commission Question 2.

line conditions collected from the sensor devices. These are better than traditional static ratings that were based on conservative estimates of weather (wind speed, temperature) conditions. Dynamic thermal line ratings may allow the transmission line to be operated closer to its physical limits and this extra capacity may allow more wind generation to be carried on a transmission line under certain conditions. AltaLink and the AESO recently conducted a joint pilot project on a transmission line in southern Alberta. Implementation and operational issues encountered during the pilot project indicated to AltaLink the need for additional research before pursuing any large-scale deployment of this technology in Alberta. The AltaLink and AESO pilot project is described in Appendix 3 – Current status of smart grid development in Alberta.

### Policy considerations

As noted, FACTS and HVDC technologies can be used to control or optimize the use of transmission lines in real-time through remote/automatic switching and control of power flows on transmission lines. Making dynamic adjustments to the transmission capacity of the AIES could have an effect on the business decisions of buyers and sellers of electrical energy in the power pool. If the making of dynamic adjustments to transmission capacity has effects on the competitive market, it may be necessary for rules to be put into place to ensure that the AESO's responsibility to ensure that the market operates in a fair efficient and openly competitive manner is properly balanced with its responsibility to ensure system reliability. It appears that the AESO has the powers necessary to make those determinations and implement rules if necessary.

The AESO and the TFOs have been using business cases, cost-benefit analyses and pilot projects to evaluate and implement new transmission technologies.[69] In general, existing technologies are being replaced when new and smarter technologies become available and demonstrate that they can provide benefits such as increased functionality, deferred capital spending, improved system control and security, reduced maintenance, enhanced reliability or reduced costs. These technologies have been justified and implemented through existing regulatory and expenditure approval processes.[70] Legislative changes, however, may be necessary if some smart transmission investments cannot pass a traditional cost-benefit study but, nevertheless, promise to provide societal benefits that would not otherwise be available. The legislative changes would allow the estimation of the value of any societal benefits to be included in a cost-benefit study and would almost certainly be controversial in its implementation.

The AESO and the TFOs are implementing what can be considered smart transmission technologies as a matter of good engineering and business practice without the necessity for them to be mandated. Further, as new technologies become available and are required the AESO has rule-making powers to make ongoing refinements to its rules and standards or practices regarding the adoption and implementation of smart transmission technologies by the TFOs in order to ensure the reliability of the transmission system.

Participants in the Inquiry did not ask for any new policies to assist the continued roll-out of smart transmission technologies. However, AltaLink observed that the current cost-of-service regulatory model employed in Alberta does not provide strong incentives for the regulated companies to improve their efficiency because "there is no opportunity to earn incrementally while there is increased risk that associated costs may not be recoverable."[71] AltaLink recognized

[69] Exhibit 99.02, AltaLink Response to Commission Question 38.
[70] Exhibit 99.02, AltaLink Response to Commission Question 28.
[71] Exhibit 99.02, AltaLink Response to Commission Questions, page 9.

that the existing regulatory approach may require modifications to adopt performance-based approaches to strengthen the incentive for smart grid investments. In 2009, the AUC approved a performance-based regulation plan for ENMAX Power Corporation.[72] The Commission has also begun a process to implement performance-based regulation for the other distribution entities in Alberta that it regulates. Transmission facility owners such as AltaLink may apply to the Commission for performance-based plans that are tailored to their specific circumstances.

The Commission also recognizes that current regulatory models provide no incentive for the transmission or distribution companies to reduce their line losses. In 2010, the Commission approved an application by ENMAX Power Corporation to implement a mechanism that would allow the utility and customers to share in cost savings achieved through a reduction in distribution line losses.[73] Similar regulatory initiatives could create greater incentives for transmission companies to pursue smart transmission technologies that would reduce line losses.

## Distribution

An electric distribution system takes electricity from the transmission system and delivers it to customers. The typical distribution system begins as the primary feeder circuit leaves the substation and ends at the customer's meter. The distribution system has traditionally operated with a one-way flow of electricity from centrally-located generation plants to end-use customers with relatively little or no monitoring and control automation.

In Alberta, the distribution of electricity is provided by investor-owned and municipal-owned distribution utilities and rural electrification associations (REAs). REAs originated during the late 1940s and 1950s. They began as farmer-owned co-operatives created in order to electrify the farms of Alberta. The REAs still provide service to mainly rural Alberta. REA and distribution company systems are intertwined in the REA service area[74] and they work together to ensure there is reliable service and no duplication of distribution lines and service.

The distribution tariffs for the cities of Red Deer and Lethbridge and the towns of Cardston, Fort Macleod, Ponoka and the Municipality of Crowsnest Pass are approved by their local municipal governments and town councils. The REAs have boards of directors that approve their associated distribution tariffs on behalf of their members. The cities of Calgary and Edmonton own their electric distribution systems. In Alberta's remaining communities, the distribution systems are owned by either FortisAlberta Inc. (southern and west-central Alberta) or ATCO Electric Ltd. (northern and east-central Alberta). Over 90 per cent of distribution system customers in Alberta are served by ATCO Electric Ltd., ENMAX Power Corporation (ENMAX), EPCOR

[72] AUC Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009.

[73] AUC Decision 2009-226: 2007-2016 Formula Based Ratemaking; Line Loss Proposals, Application No. 1550487, Proceeding ID. 12, November 24, 2009.

[74] In Alberta, most rural areas are radial networks. A radial distribution line may serve both distribution entity and REA customers and different parts of the same line may be owned by one or the other party.

Distribution & Transmission Inc. (EPCOR), and FortisAlberta Inc. (FortisAlberta). These companies' distribution services are regulated by the Commission.[75]

### Smart distribution technologies

Distribution systems are generally operated as radial systems. Radial systems are typical in rural areas and in some urban areas. The basic characteristic of a radial system is that it has only one power source for the connected group of customers. A fault on the line will result in an outage which affects all the customers on the line. Urban areas are usually served by switchable networks and are made up of a number of radial lines connected to each other. They are switchable because it is possible to connect one radial line to another by way of a switch so that a radial line (or a portion of that line) that has lost its power source can acquire power off the other radial line.

Distribution automation offers potential benefits in areas with switchable networks. It allows a smart distribution network to instantaneously detect and identify operational problems and automatically respond so as to be able to prevent or mitigate outages, power quality problems and service disruptions. A distribution automation system mitigates power outages by automatically coordinating the opening and closing of smart distribution switches to isolate the area close to the outage so that repairs can be effected while service is quickly restored to other areas on the same radial segment. This automation is made possible by communication between and among devices that include switches, reclosers and fault sensors. A pilot project conducted by FortisAlberta demonstrated that utilizing distribution automation on parts of its rural radial system provided fewer benefits and incremental efficiencies than might be expected in urban settings.[76]

A distributed automation system can be divided into three functional components: the system applications, the field equipment and devices and the communications network that links the two and makes possible the transfer of information from one to another.[77] The potential benefits of an automated and optimized distribution grid include greater system reliability (e.g., a reduction in the duration of outages), more efficient operations (e.g., better control of voltage and frequency regulation, reduced line losses), enhanced system planning (better line load forecasting capabilities) and enhanced asset management (e.g., improved equipment information). The potential benefits will depend on, and may be limited by, the terrain on which the system is situated and the design of the automated control system.

Distribution automation system applications can also remotely control and monitor the operational status of the distribution system. They are used for monitoring the voltage and remotely maintaining it within acceptable limits, for monitoring the load, power quality and flow, and for monitoring the performance of substations and transformers. These applications may also assist with fault detection, isolation and restoration of the distribution system during outages.

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[75] Government of Alberta, Department of Energy, "Statistics Information System Switching Percentage By Group" (January 21, 2011), online: Government of Alberta, Department of Energy, http://www.energy.alberta.ca/electricity/esi/Table1_Electricity_Alberta_ByGroup.pdf.

[76] Transcript, Volume 1, page 167.

[77] For details see Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

Distribution automation applications such as management system applications may aid in system design, operator training and day-to-day operations (e.g., helping to avoid overloading conductors and transformers due to more efficient system modelling) and may improve safety through automatically generated switching orders, which can be tested by software in advance. A distribution management system's simulation tools can be useful for training new control room operators and for simulating procedures for situations that may be uncommon yet critical. Through these improvements and new technologies, the useful life of some distribution system assets will likely be extended.

Smart distribution applications such as outage management systems enhance system reliability by improving outage detection and restoration. A smart distribution outage management system uses information from customer calls, network-enabled switches and transformers and different software programs to locate outages and help with the coordination of the restoration efforts, therefore reducing the outage duration. These are most effective in urban areas.

Currently, all distributors rely on customer calls to detect an outage and they are able to address many outages quite quickly with their current processes. During the Inquiry, the Commission was told that for small distribution utilities, customers calling to report power disruptions appeared to be the most cost effective means of being notified of an outage. In these companies the linemen and field workers are very familiar with the configuration of the system, and a customer call is sufficient to identify the source of the problem. For example, FortisAlberta experienced three major storm outages in the south-eastern part of the province in the spring of 2010. Power was restored fairly quickly without the use of additional smart distribution technologies. Depending on the size and configuration of the distribution system, smart distribution technologies may not provide any significant improvement over the outage management system currently in place.

Distribution automation applications may improve system reliability and affect future asset purchases (e.g., remotely-controllable line switches will be purchased in some cases, rather than manually-operated ones). However, the Commission heard that incremental potential benefits resulting from increased reliability may not significantly improve the current service quality metrics (SAIFI, SAIDI, CAIDI).[78]

The increase in reliability resulting from implementing smart distribution technologies will be different for each customer class. Industrial and commercial customers whose operations rely upon a constant flow of information (such as banking or health care) or a very high and constant power quality may potentially benefit from smart distribution technologies. Alternatively, in rural and remote areas with radial networks and where power interruptions are more frequent and weather related, implementing smart distribution technologies may not provide noticeable benefits. For example, the duration of outages may be reduced but not necessarily the frequency.

Some industries, including many agricultural operations, have generally undertaken their own investments to achieve the benefits that would otherwise be available from implementing smart distribution technologies. In the case of poultry operations, to which power is vital, higher reliability does not yield any additional benefits because producers have already invested in

[78] SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) are the most commonly used indices for measuring customer reliability on the distribution system.

equipment to protect against power interruptions. The South Alta Rural Electrification Association Ltd. (SAREA) stated that poultry operators are required to install outage alarm systems, as well as a back-up generator as a condition of becoming a certified producer. The alarm system will immediately notify the operator of a power interruption, and the back-up generator will start if the power is off for more than ten seconds.[79]

Although the increased reliability benefits for some of these smart distribution technologies may be minimal for some companies in Alberta, smart distribution technologies may be required to integrate variable generation and to accommodate the migration to two-way power flows.

In general, the implementation of smart distribution applications is widely touted as providing increased benefits and efficiencies, but applications that make sense in other jurisdictions may not necessarily apply to Alberta. For example, a conservation voltage reduction application did not make a good business case for the EPCOR service area.[80] A conservation voltage reduction application reduces the voltage of the electricity supply in order to reduce peak demand and help to balance the electric system, by decreasing the power quality.

The second functional component of distribution automation includes the field equipment and devices that are installed in substations, transformers or across lines. These are the physical components that enable the system applications to perform their functions. The deployment of advanced sensor technologies on critical equipment such as capacitor banks and transformers will provide a continuous stream of data that can increase awareness of the system's operations. The use of dynamic information, rather than static, is important for planning and maintenance purposes.[81] Greater operational awareness of the condition of the distribution system will allow operators to better respond in situations when equipment is deteriorating and needs to be replaced or repaired.

The greatest potential benefits from distribution automation system applications and smart distribution field equipment and devices arise when the applications and devices are connected through a two-way communications network, the third functional component. This communications network will allow distribution entities to remotely measure, monitor and control the system in real-time by providing dynamic information about the distribution system performance, which in turn will increase awareness of critical operational conditions, resulting in more efficient dispatch of repair crews, reduced outage times, lower operation and maintenance costs and improved asset management.

Currently, distribution system owners in Alberta are investing in smart distribution technologies that demonstrate positive benefits and are implementing them on a case-by-case basis. Each

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79 Exhibit 196.02, SAREA Supplemental Submission, page 2.

80 Conservation Voltage Reduction (CVR): Constant-resistance loads — incandescent lighting, for example — draw power proportional to the square of the supply voltage. CVR seeks to leverage this fact to reduce peak demand (peak power) by reducing the supply voltage at appropriate times; for example, when the demand on the grid is nearing a maximum, or when supply is highly constrained. Unfortunately, modern grids are also comprise sophisticated, nonlinear loads, and the effect of CVR on the power draw of these loads may be much less. In addition, such loads are often sensitive to brief voltage sags that occur from time to time. If sags occur during a CVR period, the disruption to these loads is magnified. Hence, CVR does not apply to all distribution circuits, and EDTI has not established a business case for CVR as of yet. [Exhibit 108.02 EDTI Response to Commission Question 20, pages 55 and 56].

81 Transcript, Volume 3, pages 660-661, Mr. Haag, EPCOR Distribution & Transmission Inc.

distributor is implementing different smart distribution applications, equipment and devices that are applicable to situations specific to their service area. In locations where network characteristics permit (switchable or looped networks), distribution owners have implemented distribution automation systems.[82] They have also implemented control and monitoring system applications such as SCADA, outage management systems, work force management systems and graphical information systems. These system applications are used to provide increased operational benefits. Utilities are also investing in smart distribution projects that include communication system upgrades and integration of control and protection devices and intelligent electronic devices, in order to achieve automation and enhance corrective capabilities.[83]

### Distributed generation and micro-generation

The implementation of smart distribution technologies for advanced communications, monitoring and control will enable the widespread integration of more micro-generation[84] and distributed generation resources[85] in the distribution system. Additional deployment of energy storage technologies may also help with the integration of increased amounts of distributed generation. These devices can help make the output from renewable energy resources, connected to the distribution system and which are intermittent and cannot be controlled by the owner, smoother and more readily integrated in the distribution system. Currently, most of these energy storage technologies are not commercially viable.[86]

The use of micro-generation and distributed generation may benefit customers and distribution entities by meeting local energy needs. Installing a distributed generation facility at or near the customer's premises can provide an alternative or incremental source of electricity to the distribution system or to a customer. It can also benefit the distribution entity by helping to shift and manage peak loads within the distribution system, improve reliability, and potentially avoid or reduce infrastructure upgrades. Micro-generation may also provide additional environmental benefits from reduced carbon emissions.[87]

Micro-grids[88] provide the opportunity to integrate distributed energy resources with local consumption centres on a larger scale than is economically possible with individual customers. Consumers connected to a micro-grid network may benefit from a secure, highly-reliable, and readily-available power source that can be configured to protect from interruptions on the distribution system, while supplying continuous high-quality power.

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82 Participants Response to Commission Question 12. For a list of technologies implemented by participants see Appendix 3 – Current status of smart grid development in Alberta.

83 Exhibit 69.01, Cities of Red Deer and Lethbridge Response to Commission Question 12.

84 Micro-generation resources are generation units under one MW that utilize renewable fuel sources and serve their own loads: *Micro-generation Regulation*, Section 1(1)(e), (g), (h) and (n).

85 Distributed generation is small scale power generation, typically in the range of three to 10,000 kW, which can connect to a distribution system, operate within distribution voltage levels and provide electricity close to the point of consumption.

86 Further details on the status of storage technologies can be found in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

87 ENMAX Energy Corporation introduced a program to install 9,000 micro-generation units totaling between nine to 11 MW (solar photovoltaic panels and micro-wind turbines) on residences, farms, and small commercial sites across Alberta and introducing an electric vehicle pilot program to evaluate the impacts and benefits of localized energy storage on the distribution system. [Transcript, Volume 3, page 686].

88 A micro-grid is a localized grouping of electricity generation and consumption centres that normally operate connected to a traditional distribution system. A micro-grid can also include energy storage. From the point of view of the distribution system owner, a connected micro-grid can be controlled as if it was one entity.

In Alberta, there is a relatively small number of distributed generation and micro-generation facilities, each of which was connected on a case-by-case basis with no significant difficulties.[89] Micro-generators are required to serve only their own consumption on an annual basis, and therefore the power generated into the distribution system is negligible. For both distributed generation and micro-generation, there are processes in place to ensure they are connected to the distribution system in a safe and reliable manner. Distribution entities are accommodating or tolerating the current amount of distributed generation and micro-generation on their systems. Both distributed generation and micro-generation are installed on a case-by-case basis and neither participates in the power pool.

Over time, smart distribution technologies may be required to integrate increasing amounts of distributed generation and micro-generation. As distributed generation grows, it could displace generation sources that participate in the power pool (i.e., transmission connected generation) in a significant way and therefore affect the market. The ISO rules that apply to transmission-connected generation currently do not apply to distributed generation. Moving from tolerating or accommodating distributed generation to integrating it could mean that distributed generation may have to adhere to the same ISO rules that apply to transmission-connected generation.

### Policy considerations

The current technologies employed by Alberta's distribution entities have been implemented based on business cases and best utility practices.[90] These technologies have been installed on the basis that they help utilities prevent and mitigate outages and increase the reliability of their systems as well as the safety and the life of their assets. Some of these technologies and applications were available before the emergence of the term smart grid (i.e., distribution automation, SCADA, automatic meter reading systems), but they can perform many smart grid functions. Over time, smart distribution technologies that presently do not have sufficient proven benefits to support a business case may be justifiable, as the cost of technology decreases and the experienced and aging workforce that operates the distribution system retires. As this happens, utilities will choose the investment and make the necessary regulatory applications to adopt the technologies. Participants noted that these investments "should continue to be guided by good utility practice and customer-centric business cases" and government should not mandate their implementation.[91] [92] [93]

As noted above in the Transmission section of this report, the Commission has approved a performance-based regulatory plan for ENMAX Power Corporation and has initiated a process to implement performance-based regulation for the other distribution entities in Alberta. Performance-based regulation is well suited to addressing the roll-out of smart distribution

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89 Transcript, Volume 1, page 172.

90 Exhibit 96.02 Alberta Municipal Power Systems (AMPS) Response to Commission Question 19.

91 Exhibit 102.03, ENMAX Response to Commission Question 25.

92 Exhibit 100.02, FortisAlberta Response to Commission Question 19.

93 The Consumer's Coalition of Alberta noted that a challenge will be enhancing the older or legacy parts of the distribution systems. The small progress that has occurred has not been motivated by government regulation, but rather because it offered the distribution companies a positive return on investment. A sentiment expressed by UtilityNet, and echoed by other participants, is that "market needs, driven by solid business cases, should be the only reason for proceeding forward." [Exhibit 107.01, Consumers' Coalition of Alberta Response to Commission Question 2 and Exhibit 113.01, Utility Network and Partners Inc. Response to Commission Questions, page 12].

technologies that will improve the productivity of the entities. Instead of having to prove a positive business case to the regulator, distribution entities are incented to seek out new technologies that improve their performance because they will be able to reap financial benefits for doing so. If smart grid investments also yield societal benefits that can be quantified, a properly constructed performance-based regulation plan can recognize those benefits through a number of mechanisms. Legislative changes, however, may be necessary to permit recognition of societal benefits in this way.

The Commission has already approved a regulatory mechanism for ENMAX Power Corporation to allow the sharing of the financial benefits of reducing distribution line losses. To the extent smart distribution technologies can be employed to reduce line losses, these types of regulatory mechanisms can promote the deployment of smart distribution technologies.

## Smart meters

### The evolution of meters

The meter is the instrument that measures electrical energy usage for each customer and depending on the complexity of the customer's electricity system, one or more meters may be located on the customer's premises. It is typically located at the customer's premises and is the point at which the distribution entity-owned system connects to the wiring owned by the customer in the home or business. Until fairly recently, the meters deployed on electrical systems around the world have been electromechanical meters. For larger customers, these electromechanical meters could measure electrical energy usage and peak energy demand. For residential and small business customers, the meters typically measured only the total amount of electrical energy consumed during a period of time (typically a month). In order to read the meter, representatives of the utility company would visit the customer's premises or, in other cases, the customer would be asked to read the meter, mark down the reading on a card and mail the card with the monthly or other periodic reading to the utility company for billing purposes.

This is changing. Electricity meters are evolving and becoming smarter in three ways. First, they have embedded in them electronic communications devices capable of sending and receiving information to and from the distribution entity and the retailer and sending information to the customer. Second, they have the capability to be read remotely, have service connected and disconnected remotely, detect power outages, monitor power quality (including voltage) and, detect fraud and theft of electricity remotely. Third, instead of usage information being recorded by counting the revolutions of an aluminum disc, new smart meters are electronic and digital. They display usage on an LCD or LED display in real-time or measure usage over multiple periods such as every hour, every 15 minutes or even more frequently to enable multi-period pricing and have data storage capabilities built into them. This detailed usage information can be delivered automatically through the electronic communications device, or the meter can be queried to send the stored information to the distribution entity or others with access to the meter information, such as the retailer and customer.

Not all meters available in the market perform the same functions. Today, it is possible to purchase smart meters that include all of these functions and more or to buy meters that provide only some of these functions. Information gathered during the Inquiry suggests that basic

electromechanical meters will cease to become available in the market at some point and that all future meters will be capable of supporting a variety of advanced features. The record also shows that the costs of purchasing and deploying smart meters are already low enough to be competitive with traditional cumulative meters[94] (although the depreciation lives will likely be shorter). The only choice for purchasers of these newer smart meters will be which of the available features they will actually use.

The size and nature of the communications, operating and storage systems required to support smart meters depends on what the meters are being asked to do. If smart meters are used only for the operational purposes and for measuring simple traditional cumulative usage, it will not be necessary to change the back office operational, billing and settlement systems or data storage capacity currently in place to support the competitive generation and retail markets. However, it will be necessary to establish communications links from the meters to the distribution company business offices to handle the data to support the operational functions enabled by smart meters.

Costs increase significantly once the decision is made to measure and price electricity across multiple time periods such as peak, off-peak and critical-peak periods. In order to implement multi-period pricing, more frequent meter reads are required, which result in significant increases in the requirements and costs for back office operational, billing and settlement systems. In addition, the communications link between the smart meter and the distribution company business office may have to be upgraded from what it would be to handle operational functions alone. There would also likely be significant increases in data storage requirements because any data used for billing purposes must be stored for at least eight years to satisfy federal and provincial legislation and regulatory requirements.[95] With multi-period pricing, it is expected that significantly more storage capacity would be required. It is the extensive system of smart meters, communications devices and networks, back office operational, billing and settlement systems and large data storage systems that collectively are commonly referred to as advanced metering infrastructure or AMI.

### Potential benefits of smart meters

Participants in the Inquiry discussed a number of potential benefits of adopting smart meters. These can be grouped into three categories – operational benefits, consumer benefits and societal benefits – although to the extent that operational benefits and societal benefits arise, consumers will benefit indirectly.

The potential operational benefits of adopting smart meters include lower costs from remote meter reading and the ability to connect and disconnect customers remotely, power quality monitoring, fraud and theft protection and the potential for faster notification of power outages (although many distribution company witnesses minimized the importance of this feature, particularly those that serve smaller geographic areas, stating that they already learn of power outages very quickly simply by people telephoning to notify them).[96] Participants in the Inquiry emphasized that the extent to which these benefits could arise would depend on the

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94 The SAREA stated that it had purchased meters capable of remote meter reading as well as measuring multi-period usage information because those meters were the most cost effective even though SAREA will not be using the multi-period usage function. [Transcript, Volume 3, pages 723 and 724]

95 See Appendix 7 – Smart metering technologies and related matters.

96 Transcript, Volume 1, page 162, FortisAlberta; Transcript, Volume 1, page 196, AFREA; Transcript, Volume 1, page 220, AMPS; Transcript, Volume 2, page 491, cities of Red Deer and Lethbridge.

circumstances of each individual company.[97] For example, rural distribution entities can expect to realize greater cost savings per customer from remote meter reading than an urban distribution entity would because of the greater distances between rural customers. One example of an additional operational benefit is the potential for the distribution company or aggregators to develop and market programs to customers who would allow them (with the customer's consent) to reach into the home through smart meters and electronic communications in order to turn off interconnected customer appliances or draw electricity from electric car batteries plugged in at home when there is a need to reduce system-wide demand or address more localized conditions.

Participants recognized that it is not necessary for smart meters to measure and provide multi-period usage information in order to realize any of these operational benefits. All that would be necessary for those benefits to be realized is that the smart meters be installed and that they communicate with distribution business offices and, in the case of consumer energy reduction programs, provide a connection into a home area network. Other AMI features would not be necessary.

While there may be some additional operational benefits that result when smart meters are deployed along with smart transmission and distribution technologies, it is not necessary to deploy smart meters in order for the distribution company or any of the transmission companies or generation companies to benefit from their own smart transmission or smart distribution investments. When asked, the AESO[98] and the TFOs[99] acknowledged that they did not need the multi-period usage information available from smart meters to assist in the planning or the efficient operation of the transmission system. Similarly, the distribution companies stated that the multi-period usage information would not assist them in the efficient operation of the distribution system (i.e., improving their SAIDI, SAIFI and CAIDI results). Indeed, it is possible to deploy and realize the benefits of smart meters and the related communications, operational and data storage systems without deploying smart transmission or distribution technologies.

Smart meters and AMI make it possible for customers to see changes in the price of electricity during the day and to move some of their usage from times when prices are higher to times when prices are lower and to have these changes in their time of consumption reflected on their bill and potentially lower their energy costs. Some participants suggested that there are potential consumer benefits from smart meters that arise from the potential for consumers to simply monitor their usage and modify their consumption behaviour and perhaps for some customers to lower their energy costs.[100] Some studies suggest that simply making the electricity consumption visible to the consumer will result in reductions in usage.[101] Of course, as participants acknowledged, there is no need to invest in smart meters or AMI to make real-time usage information visible to the consumer. Other far less expensive alternatives that perform that function are already available in the market.[102]

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97 Exhibit 99.02, AltaLink Response to Commission Question 28.

98 Transcript, Volume 1, pages 11-12.

99 Transcript, Volume 1, pages 59 and 63.

100 Exhibit 88.01, Direct Energy Response to Commission Question 40.

101 The Economist Print Edition, "Building the Smart Grid" *The Economist* (June 4, 2009), online: The Economist http://www.economist.com/node/13725843; BC Hydro, "Smart Metering and Infrastructure Program Business Case" (January 2011), online: BC Hydro http://www.bchydro.com/etc/medialib/internet/documents/smi/smi_business_case.Par.0001.File.smi_business_case.pdf.

102 Exhibit 82.02, CAREA and SAREA Response to Commission Question 12.

The societal benefit from smart meters and AMI is the more efficient use of resources as customers, faced with retail prices that more closely reflect changes in the Alberta power pool prices, adjust their use during various time periods so that the value to them of the electricity they use more closely reflects the resources used to supply that electricity. Additional societal benefits may result if, for example, there is a reduction in peak demand which curtails future expansion of transmission or distribution infrastructure, reduces peak wholesale electricity prices and/or reduces $CO_2$ or other emissions as consumers change their electricity use.

Many participants in the Inquiry expressed reservations about whether these potential consumer and societal benefits could actually be achieved in Alberta through the introduction of multi-period pricing plans because of the unique market and structural circumstances. In particular, participants pointed to Alberta's high load factor (average usage as a percentage of peak usage), the large portion of the residential customer's bill that does not vary with use, the competitive power pool, the types of generation (primarily coal-fired and natural gas-fired), peak demand periods that do not necessarily correspond to peak pricing events, and peak pricing events that do not necessarily correspond to peak demand periods, the small percentage of electrical energy usage by residential and small commercial customers (who do not currently have time-of-use meters or pricing available to them), the absence of significant residential air conditioning load (which results in high peak usage in summer months in some jurisdictions) and the operation of the competitive retail market, all as limiting the potential benefits from multi-period pricing and, therefore, from smart meters and AMI.

Other potential benefits from the deployment of smart meters and AMI have been claimed in other jurisdictions. For example, in Texas one of the benefits cited for the roll-out of AMI is that it will provide more choices for customers in the competitive retail market.[103] In Ontario and the United States, governments have embraced smart grid deployment, including smart meters, as a way to create jobs and stimulate economic recovery. None of the participants appearing at this Inquiry, however, argued that smart grid technologies should be deployed in Alberta for these reasons or that the Alberta government should fund this deployment.

### Current smart meter deployment in Alberta

In Alberta, industrial and large commercial customers account for approximately 70 per cent of overall electricity consumption. These customers are generally already equipped with smart meters (referred to as interval meters) that allow for detailed multi-period pricing and real-time or near real-time meter reading.[104] Interval meters record the amount of energy used at a site as well as the peak usage (called demand) during a specified period of time. This information is recorded on separate registers within the meter in 15 minute intervals. Consumption is measured

[103] Texas House Bill 2129 (79R) Section 8. "In recognition that …new metering and meter information technologies, have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of transmission and generation assets, and provide more choices for consumers, the legislature encourages the adoption of these technologies by electric utilities in this state."

[104] Currently there are approximately 7,000 interval meters installed in the province mainly at industrial and large commercial sites. The amount of electrical energy that these interval-metered sites are consuming on an annual basis represents approximately 60 per cent of the total electrical energy consumption in the province. Interval meters are not new, but they are similar to smart meters in the ability to record consumption data for multiple price periods. They are also connected to the distribution entities business offices by electronic communications. Many of the interval meters have direct real-time communications with the customers' operations. For the purposes of this report interval meters will be considered smart meters.

in kilowatt hours (kWh) or megawatt hours (MWh), while demand is measured in kilowatts (kW), megawatts (MW) or kilovolt amperes (kVA).

Since the introduction of competition in the retail market, a market rule has been in place that requires sites with a peak demand over two megawatts to have an interval meter. Each distribution entity, in its terms and conditions for service, can establish its own threshold for when an interval meter is required at a site. Sites that register demand as low as 150 kVA (which on a comparative basis is significantly less than two megawatts, essentially being 150 kW) are now being equipped with interval meters. The move to installing interval meters at a lower demand threshold level was due in part to distribution entities responding to customers' requests for more detailed information regarding electric energy usage and to the distribution entities' desire to operate their system more efficiently and bill more accurately.[105]

Interval meters can also be equipped with pulse outputs. Pulse outputs allow the customer to connect consumption monitoring and control equipment to the meter to obtain real-time data about various metered quantities, such as consumption and demand. Commercial and industrial customers can then use the data provided by the meter output pulses, in conjunction with pool price information, to make informed decisions regarding energy usage.

Distribution entities obtain interval meter pulse data through the use of a telecommunications system – typically by a telephone landline or by a wireless communications device. The data is collected on a daily basis by the distribution entity in its interval meter data collection system, validated by the distribution entity, converted from the pulse data into meter reads and then sent through electronic communications to the load settlement agent and retailers for their load calculation and billing processes.[106] The communications infrastructure, billing and settlement systems, as well as data storage systems sufficient to employ these meters are already in place for these customers.

Residential customers and small commercial customers account for approximately 30 per cent of overall electricity consumption in Alberta. Typically, they have cumulative meters that only measure how much electricity was used in total since the last time the meters were read. Readings are taken either visually or by radio frequency, and entered into a hand-held device for manual meter reading. At the end of the day, all meter information collected is downloaded into the meter data management system, in which the validation, edits, and estimation are performed in order to ensure the data accuracy. Some of these meters are electromechanical meters and some are capable of automatic meter reading. Even where smart meters capable of measuring electricity usage at multiple time periods are in place, however, the meters continue to be used in the same way cumulative meters are used. The price structures necessary to take advantage of those capabilities are not offered, and the communications infrastructure, billing systems, as well

[105] ENMAX: "The move to interval meters at the 150 kVA level will provide customers with enhanced information to make improved consumption decisions and have the potential for additional supply contract offerings from the retailer of their choice.", online: http://www.enmax.com/Power/Tariffs/Our+Tariffs/Interval+Meter+Threshold.htm.
FortisAlberta: "Interval metering measures the amount of energy used at a site and sends in the meter data to a recorder in 15-minute intervals. Interval meters and related equipment are installed for a customer who has a demand of 333 kW or greater. Newer electronic meters have a built in recorder that captures interval data", online: http://www.fortisalberta.com/Default.aspx?cid=70&lang=1.

[106] See Appendix 7 – Smart metering technologies and related matters for more information.

as data storage systems necessary to fully employ those functions, are not in place, although the existing settlement system is capable of hourly settlement.

Few residential and small commercial customers in Alberta have smart meters installed at their home or premises. However, FortisAlberta Inc.,[107] has installed meters for remote meter reading in its service area in order to reduce its meter reading costs. ATCO Electric Ltd.[108] has installed remote meter reading capability on electromechanical meters in its service area to reduce meter reading costs. Both of these companies serve primarily rural areas and employ power line carrier analog communications systems to carry the meter data back to the distribution company business office. The City of Lethbridge[109] electric utility has also deployed automatic meter reading in order to reduce meter reading costs. The SAREA recently replaced all of its meters with smart meters capable of providing remote meter reading functions[110] and also capable of providing multi-period usage information. However, the SAREA has chosen not to employ or even record the multi-period usage information at this time. It collects usage data and bills customers as though the meters were traditional cumulative meters.

EPCOR Distribution & Transmission Inc. recently applied to the Alberta Utilities Commission to remove 10,000 old cumulative meters and replace them with smart meters in order to realize operational benefits such as remote meter reading. The Commission denied the application for two reasons: that the business case for the project was not well founded and the absence of a provincial smart meter policy.[111]

Currently in Alberta, limited automatic meter reading is deployed. Other than the power line carrier communications links deployed by FortisAlberta Inc. and ATCO Electric Ltd., it appears from the record of the Inquiry that virtually none of the distribution entities have electronic communications systems in place that would allow the meter to communicate directly with the distribution entities' business office systems.[112]

### Deployment of smart meters and advanced metering infrastructure (AMI)

The decision whether to deploy smart meters and AMI and, if so, how it might be deployed, depends on the unique characteristics of the jurisdiction in which the deployment is being considered and the unique circumstances of each distribution company. Not all of the potential benefits of smart meters and AMI can necessarily be realized in all jurisdictions or by all companies. In Alberta, there are a number of unique characteristics that must be addressed when considering mandated smart meter and AMI deployment with multi-period pricing plans for residential and small commercial customers.

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107 Exhibit 100.02, FortisAlberta Response to Commission Question 12.

108 Exhibit 91.01, ATCO Electric Response to Commission Question 12.

109 Exhibit 69.01, Cities of Red Deer and Lethbridge Response to Commission Question 12.

110 SAREA currently reads these meters monthly by arranging for a fly-over to collect meter data through a radio signal [Transcript, Volume 3, page 724]. The communications device in the meter used for remote meter reading is a transponder that emits radio waves that are picked up by an aircraft as it flies over the meter sites.

111 AUC Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID. 437, October 28, 2010, page 60.

112 Although all distribution entities do have electronic communications systems in place or through third party providers to provide the back office billing, settlement and data storage necessary to comply with the requirements of the competitive generation and retail markets.

First, Alberta's retail electricity market is open to competition. If the value of the operational benefits alone does not justify the roll-out of smart meters and AMI, it will be necessary to also consider whether there is sufficient value of any potential societal and customer benefits made possible by multi-period pricing plans, when added to the value of the operational benefits, to justify the roll-out.[113]In the competitive retail system, a decision to mandate smart meters with multi-period usage measurement and AMI cannot be accompanied by a policy requiring all customers to subscribe to a multi-period pricing plan if the retail market is to continue to function so that retailers can choose to offer pricing plans attractive to a variety of customers.[114,115,116]

Second, the electrical energy usage in Alberta by residential and small commercial customers is a small percentage of the total usage and there is an absence of significant residential air conditioning load (which results in very high peak usage in summer months in some jurisdictions).[117,118] In these circumstances, even a relatively significant electricity consumption response to multi-period pricing plans by these customers might not have a significant impact on overall system consumption or demand at peak times.[119,120]

Third, in Alberta, the peak demand periods do not necessarily correspond to peak pricing events in the power pool, and peak pricing events do not necessarily correspond to peak demand periods. This is due largely to the relatively high and flat daily load profile, which has the effect of making the generation supply mix the most significant determinant of the hourly pool price. Consequently, the hourly pool price is influenced by events such as planned and unplanned outages at coal-fired generation plants, the amount of wind generation, natural gas prices and the operational capabilities of the provincial interties between Alberta, Saskatchewan and British Columbia rather than by the level of consumer demand only.[121,122] Demand response programs promoting energy efficiency and conservation tied to multi-period pricing plans may therefore have little impact on the daily load profile and the hourly pool price.[123]

Fourth, the fuel sources for electricity generation are primarily coal and natural gas. As described in the Generation section of this report, coal provides base-load generation and natural gas-fired generation is used primarily to supply electricity during peak periods. Accordingly, a reduction in electricity use during peak periods is likely to displace natural gas-fired generation and if there is a resulting increase in off-peak periods it could increase coal-fired generation, quite the opposite effect to a policy objective of reduced $CO_2$ and other emissions.[124]

Fifth, the competitive generation market in Alberta allows electricity prices to be determined in the Alberta power pool. While certain operational characteristics of the Alberta power pool may

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113 Exhibit 108.02, EDTI Response to Commission Question 52.
114 Participant Response to Commission Question 47: Exhibit 111.01 (Rick Cowburn); Exhibit 99.02 (AltaLink); Exhibit 91.01 (ATCO); Exhibit 112.02 (UCA).
115 Transcript, Volume 3, page 711.
116 Exhibit 88.01, Direct Energy Response to Commission Question 45.
117 Participants Response to Commission Question 50: Exhibit 99.02 (AltaLink); Exhibit 100.02 (FortisAlberta).
118 Exhibit 159.01, Rick Cowburn Response to Commission Question 66.
119 Exhibit 117.01, AFREA Response to Commission Question 47.
120 Exhibit 111.01, Rick Cowburn Response to Commission Question 46.
121 Exhibit 82.02, CAREA and SAREA Response to Commission Question 43.
122 Exhibit 113, Utility Network and Partners Inc. Response to Commission Question 3.
123 Exhibit 102.03, ENMAX Response to Commission Question 49.
124 Transcript, Volume 1, page 152.

mean that the power pool prices do not precisely reflect the cost of producing electricity, the Alberta power pool prices are related to cost in a general way and are the best measure of cost that is currently available in Alberta. The Alberta power pool prices can be used as a measure of cost when determining time periods and prices for customers in the context of multi-period pricing and other programs such as direct load control permitted by smart meters and AMI.[125] For more detail see Appendix 5 – Cost-benefit methodology.

Sixth, the Alberta electricity market has a relatively high load factor, averaging 80 per cent from 2004 to 2009.[126] In other words, the load is relatively flat. Today, industrial and large commercial customers can adjust their consumption in response to changes in the Alberta power pool prices but residential and small industrial customers cannot.[127] Therefore, the sources of any additional changes in system load factor would have to come from residential and small commercial customers responding to prices that reflect changes in the Alberta power pool price. The scope for such an improvement in system load factor is limited, however, because with such a flat load, the difference between economically efficient peak and off-peak retail prices may not be significant enough to change energy consumption patterns to affect the system load.[128,129]

Seventh, a significant percentage of a typical residential customer's bill does not vary with use and significant kilowatt hour charges do not vary by time of use. There is a small fixed monthly rate for administration, a fixed charge and kilowatt hour rate for distribution and a kilowatt hour rate for transmission. Retailers pass on to customers the distribution rates and transmission rates billed to them by the distribution companies. These rates do not vary according to peak and off-peak periods. The rate is set at the beginning of each year, and the same fixed rate or rate per kilowatt hour is charged throughout the year (subject to deferral account adjustments).[130] As a result, the effect of reflecting Alberta power pool prices in either real time or in multi-period pricing plans for customers will be muted because those price changes are likely to represent only a small proportion of the bill.[131]

In the Order-in-Council, the government has asked the Commission to provide a cost-benefit methodology by which to assess smart grid initiatives. Appendix 5 – Cost-benefit methodology, provides a methodology to assess the costs and benefits of rolling out smart meters with multi-period pricing capabilities and AMI. This methodology, which starts with operational and customer benefits, includes the assessment of societal benefits that might arise from smart meter and AMI deployment. Smart grid initiatives in other industry segments (e.g., transmission and distribution) have deployed smart technologies based on their internal business case methods. These methods can continue to be used to justify their smart technology investments and could also employ measurements of societal benefits in the future, if necessary.

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125 Exhibit 91.01, ATCO Response to Commission Question 45.

126 As compared to other jurisdictions: Ontario, Texas and California. For further details see Figure 6 (2009), Appendix 2 – Overview of the Alberta electricity market.

127 Participants Response to Commission Question 43: Exhibit 103.01 (AESO); Exhibit 99.02 (AltaLink); Exhibit 88.01 (Direct Energy).

128 Exhibit 103.01, AESO Response to Commission Question 46.

129 Transcript, Volume 1, page 115.

130 Participants Response to Commission Question 43: Exhibit 111.01 (Rick Cowburn); Exhibit 100.02 (FortisAlberta).

131 Exhibit 99.02, AltaLink Response to Commission Question 51.

The cost-benefit methodology is flexible enough to permit the government to model a number of roll-out scenarios for smart meters and AMI. It can be used to model a mandatory roll-out of smart meters province-wide or on a company-specific or customer group basis. It can also be used to model a mandatory roll-out of smart meters and AMI coupled with multi-period pricing plans for the regulated rate option or optional plans available from competitive retailers. With it, the government can model the expected effects of hourly retail prices based on the hourly pool prices or less frequent retail price changes based on analyses of the power pool prices during various peak and off-peak periods.

In order to predict changes in consumption in response to price changes, the model employs price elasticity or demand response information for various customer classes or sub-groups in various time periods. This information can be derived from historical Alberta data or price elasticity of demand information from similar jurisdictions. However, during the Inquiry, a number of participants suggested that the government conduct pilot projects in Alberta to assess the level of demand response that could be expected. The data from these pilot projects would be used to calculate various price elasticities of demand for various time periods that could then be included in the cost-benefit analysis. Such pilots have been carried out routinely in other provinces such as British Columbia and Ontario and in several states in the United States.

The government could also attempt to estimate the value of reductions in $CO_2$ or other emissions based on assumptions of future demand and generation mixes and by applying a dollar value to any estimated reductions in $CO_2$ or other emissions.[132] Although this approach would be speculative and controversial, it is theoretically possible to attempt but could be expected to offer no more than a broad estimation.

### Policy considerations

Industrial and large commercial customers consume approximately 70 per cent[133] of the total electrical energy in the province. These customers are already equipped with smart metering and communications technologies such that they are able to make informed decisions regarding energy use. Consequently, there appears to be no need for a smart grid policy development for this segment of the market.

The most important policy decision is whether to proceed with a mandated smart meter and AMI roll-out for residential and small commercial customers or to rely on the natural evolution and deployment of smart meters to achieve the provincial energy strategy objectives. The cost-benefit methodology provided in Appendix 5 will allow the government to model a range of roll-out scenarios in order to assist in determining whether to mandate a roll-out. If such a decision is made, the cost-benefit methodology will also assist in selecting policy choices such as scope, timing and functional requirements.

The scope of a mandated roll-out could be limited to larger companies and could exclude some distribution entities, such as the REAs and small municipal utilities. These entities expressed concerns about their ability to absorb the cost of smart meters and AMI. The customers served by these distribution entities account for a very small percentage of the province's total electrical energy consumption.

[132] Exhibit 97.01, The Pembina Institute Response to Commission Question 28.

[133] A precise number is not available. This number is estimated using Figure 7 from Appendix 2 – Overview of the Alberta electricity market, and omitting the industrial on-site consumption.

Timing options could also include a specified time period or to wait for the normal replacement cycle for deployment of smart meters. Functional requirements could include minimum requirements such as the ability to measure usage across multiple periods, customer and retailer access to the meter data, remote meter reading and remote disconnect features as well as others available in the market.

Minimum meter functionality requirements, including communications protocols where interconnection is required between the distribution company and other entities and data access protocols for access to the meter information by retailers and others, will have to be developed whether or not the government chooses to mandate a smart meter and AMI roll-out.

The deployment of smart meters and AMI whether mandated or in response to market demands will result in a higher frequency of meter reads and data if accompanied by the introduction of multi-period pricing plans. This will substantially increase the volume of data produced, exchanged and processed and will result in greater data storage requirements. Extensive changes could be required to the information systems of all the participants (distributors, retailers, the AESO, intermediaries such as data management and billing management providers) depending on the roll-out model chosen and the costs could be significant.

At the present time, neither the regulated rate option nor most of the services offered in the residential and small commercial retail market offer rates that differ across times during the day.[134] Nor has there been significant demand for these types of services.

Participants to the Inquiry acknowledged that a mandated roll-out of multi-period pricing plans to residential and small commercial customers would be difficult because the retail market is open to competition. One option discussed during the Inquiry was that the government could choose to require that the regulated rate option, which is currently a flat kilowatt hour rate across all time periods, be converted into a multi-period pricing plan. Consumer groups objected to such an option on the basis that they expected that some customers would experience significant increases to their electricity bills if they were placed on a multi-period pricing plan. Direct Energy[135] and other competitive retailers argued the regulated rate option should not be used to roll out multi-period pricing plans. They argued that the retailers should have the opportunity to develop a variety of pricing plans made possible by smart meters and AMI and use those various plans to attract customers to their competitive services.[136] In addition, consumer representatives[137] argued that customers currently subscribed to the regulated rate option should not be forced to take multi-period pricing plans if they did not choose them and that a decision to convert the regulated rate option would simply force those (typically small) customers to take flat rate pricing options offered by the competitive retailers when those customers had already chosen not to take service from a competitive retailer.

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[134] There are some residential customers and small commercial customers who do not have access to smart meters and hourly pricing who nevertheless subscribe to a service that offers to bill customers according to the hourly pool price. Spot Power and Bow Valley Power bill customers according to the hourly pool price but cannot bill based on actual usage. Instead, they bill customers subscribing to their services based on the load profile created by the distribution entity for an average customer in the rate class of the customer.

[135] Exhibit 88.01, Direct Energy Response to Commission Question 2.

[136] Transcript, Volume 2, page 362.

[137] Transcript, Volume 2, pages 438-439.

If the government chooses not to mandate the roll-out of smart meters with multi-period pricing capabilities and AMI, there might still be some residential and small commercial customers who would be interested in multi-period pricing plans and also the opportunity to gain real time access to their own consumption data. In order to ensure that there is an opportunity for the retailers and others to offer these plans and home energy management services, it will be necessary for a number of issues to be addressed through rules or other policy instruments.

An important issue to consider is ownership of the meter.[138] Three options were discussed during the Inquiry. The meter could be owned by the distribution company (as it is today), by the retailer or by the customer. One of the province's largest competitive retailers (Direct Energy) stated[139] that while meters could be owned by the retailer or customer, Direct Energy would not object to the distribution company owning the meter. Direct Energy recognized that the distribution company would also need access to the meter for operational purposes as well.

As noted above, based on the record of this Inquiry, the Commission expects that, in time, all residential and small commercial meters deployed by the distribution companies in Alberta will have communications devices installed in them and have the ability to measure and bill electricity either in real time or in multiple periods such as hourly or other intervals. As the Commission learned from the SAREA, these meters can be deployed cost effectively today even if the multi-period measurement function is not employed.[140] The Commission also learned, however, that meter manufacturers currently offer smart meters that perform a variety of different functions.

If the government were to establish a policy that customers in the future should have the opportunity to subscribe to multi-period pricing plans and that meters are to be owned by the distribution company, it would be necessary for the government to mandate that all new meters installed by the distribution companies, when current meters have been fully depreciated, be capable of measuring multi-period usage so that the retailers would have the opportunity to offer multi-period pricing plans to all customers. One option in these circumstances is that the distribution company would record the usage information for the retailer and pass it on periodically to the retailer for billing purposes. This policy, therefore, would also require that the government mandate that the distribution companies provide for the electronic communications links from the meters to the distribution companies' business offices. The extra costs incurred by the distribution company to record the multi-period usage information for the retailer, pass it on to the retailer and store it, would have to be recouped from the retailer or retailers using that information so that distribution customers not subscribing to multi-period pricing would not be responsible for the costs incurred for that purpose. The existing billing and settlement processes

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138 Section 105(1) of the *Electric Utilities Act* places certain duties on the owners of distribution systems in relation to meters:
(e) to install and remove meters and perform metering, including verifying meter readings and verifying accuracy of meters that are directly connected to the owner's distribution system; and
(g) to provide to a retailer or the owner's regulated rate provider sufficient, accurate and timely information about the retailer's or the regulated rate provider's customers, including metering information about the electricity consumed by those customers in order to enable the retailer or regulated rate provider to bill and to respond to inquiries and complaints from customers concerning billing for electricity services.

139 Exhibit 88.01, Direct Energy Response to Commission Question 36.

140 It is important to note that the SAREA replaced its meters in the ordinary course of business and did not likely have concerns about recovering the remaining undepreciated costs of the old meters.

as well as storage requirements of the distribution company would remain unchanged for distribution and transmission billing and for other retail billing functions.

The principal disadvantage of this approach is that customers would have to wait until the existing meters were ready to be replaced before they could avail themselves of a multi-period pricing plan. In order to address this issue, government policy could require distribution companies to replace existing meters over a specified time period such as five or ten years. In such a case, any cost of the old meters not already recovered through depreciation charges would still have to be recovered from existing customers.

In the alternative, the government could require distribution companies to replace existing meters for those customers requesting the change. In such a case, the remaining unrecovered depreciation expense for the old meter would have to be estimated and recouped from the customer or retailer, once again so that remaining customers are not required to pay those remaining depreciation charges.

Policies could also be established to allow customers or retailers to purchase their own smart meters.[141] Some of the participants stated during the Inquiry that they did not object to customers or retailers owning the meters as long as the distribution company had access to the usage information necessary for their own billing purposes.[142] In this case, the removal of the old meter might raise unrecovered depreciation expense issues. There might also be other costs to the distribution company that would have to be recouped from the retailer or the customer so that the remaining distribution customers were not required to cover the costs caused by the customer or retailer in these circumstances through the regulated revenue requirement. Standards and minimum meter functionality would also have to be established in this case in order to ensure compatibility with the distribution company's systems. One disadvantage of this approach is that the customer might find itself locked in to its retailer until the meter costs have been recouped or might find that its own meter restricted its ability to change retailers in the future because of unique features of the meter that might not be compatible with another retailer.

If the distribution company either did not own the meter or owned the meter but did not handle the multi-period information for the retailer, all of the meter information could be made available to the retailer directly from the meter. In this case, the distribution company would not be required to change its communications, billing and settlement or other back office systems and would not have to add additional data storage capacity because the distribution company's method of measurement and billing would not change. However, if retailers were to own the meters, they would be required to make arrangements to store the data in order to comply with federal legislation and Alberta regulatory requirements. The costs of those arrangements would have to be recouped through the competitive retail offering prices. Various third-party service providers would likely emerge to provide the billing, settlement and storage functions to a number of retailers and the retailers would have every incentive to find the most efficient method of providing electronic communications links from the meter to their own operations or those of a billing service provider.

[141] An amendment to Section 105(1) of the *Electric Utilities Act* would be required.
[142] Transcript, Volume 1, page 176.

If retailers or customers owned the meter, they would have to satisfy federal and provincial legislation and regulatory requirements[143] for verification of metering devices and data storage, among other requirements. In addition, if the distribution company were to avail itself of any of the operational functions in the meter (such as remote meter reading) the meter owner should be entitled to a payment or credit for use of those functions. There could also be other operational and regulatory issues that would have to be resolved if the distribution company did not own the meter.

Many roll-out options driven by market demand and the ingenuity of retailers operating in a competitive market are likely to arise. Standards and minimum meter functionality such as multi-period usage measurement and real time usage data streaming to the customer would have to be established in order to ensure that customers were assured of competitive choices in the market.[144] A collaborative effort involving all the stakeholders including customer representatives is required to successfully implement the necessary market-wide changes and to ensure that the incentives for innovation and risk taking that characterize competitive markets are not unduly stifled by standards and procedures. The development of these standards and procedures should be guided by clear policy objectives in much the same way as the Alberta Tariff Billing Code was developed and implemented.

## Retail and customer

### Background

The retail electricity market in Alberta opened to competition on January 1, 2001. Customers who previously were served by a regulated service were now able to choose their electricity retailer. At the same time, the government mandated the availability of a regulated rate option (RRO) service for eligible customers who had not entered into a contract with a competitive retailer. Retailers are entities that purchase electrical energy from the power pool and re-sell the electrical energy to customers. Retailers are also responsible for billing customers. There are three types of retailers who operate in the market: regulated rate option providers, competitive retailers and self-retailers (customers who purchase electricity directly from the power pool).

The restructuring of the electricity market that provided for customer choice fragmented the former monopoly retail activities into regulated and competitive components. It also led to an increase in the number of transactions and participants involved in producing, exchanging and processing billing data. This situation created opportunities for new entrants to participate in the market and provide support services and back office functions to the various retailers in such areas as data management, administration, energy and financial reporting, customer information systems and customer relationship management.

The increased complexity in business processes made it crucial for data exchange and transaction rules to be standardized to the greatest extent possible so that customers could be billed in a timely and accurate manner. The current market rules and business processes, which are

[143] See Appendix 7 – Smart metering technologies and related matters.

[144] For example, standards could include a requirement that meters are capable of providing access to usage data for the distribution company and the retailer, with the consent of the customer. In addition, standards could require that the meters also be capable of providing real-time usage information to the customer.

established and overseen by the AUC, were developed to utilize monthly meter reads as the basis for billing customers with cumulative meters for electrical energy consumption. The billing, settlement, data storage and communications systems necessary to support this market structure are in place.

### Regulated rate option

Each owner of an electric distribution system must make available to eligible customers in the owner's service area the option of being supplied electricity services in accordance with a regulated rate tariff instead of purchasing electricity services from a retailer.[145] Customers who consume less than 250,000 kilowatt hours of electrical energy per year and have not entered into a contract with a competitive retailer are eligible to receive electricity service under the RRO. The owner may provide the electricity service under its own regulated rate tariff or authorize another party to provide this service on its behalf. If the owner delegates the responsibility, this party is referred to as the regulated rate option provider.

The largest owners of electric distribution systems in Alberta are ATCO Electric Ltd., ENMAX Power Corporation, EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. ATCO Electric Ltd. serves rural and urban communities in northern and eastern Alberta. ENMAX Power Corporation serves customers in the city of Calgary while EPCOR Distribution & Transmission Inc. serve customers in the city of Edmonton. FortisAlberta Inc. serves rural and urban communities in southern and western Alberta. These owners delegated the responsibility of providing the RRO service within their service area. Direct Energy Regulated Services is the regulated rate option provider in the ATCO Electric Ltd. service area, ENMAX Energy Corporation provides the RRO service in the city of Calgary on behalf of ENMAX Power Corporation while EPCOR Energy Alberta Inc. is the RRO provider for the city of Edmonton as well as for FortisAlberta Inc. The regulated rate tariffs of these RRO providers are approved by the AUC.

Electric distribution systems that are municipally-owned consist of the cities of Red Deer and Lethbridge, the towns of Cardston, Fort Macleod, Ponoka, and the Municipality of Crowsnest Pass. All these owners, except the city of Lethbridge, appointed ENMAX Energy Corporation to be their RRO provider. The city of Lethbridge provides the RRO service to its customers. The regulated rate tariffs of the municipally-owned distribution utilities are approved by their respective municipal councils.

The board of directors of each rural electrification association that owns an electric distribution system approves the RRO rate on behalf of its members.

With the inception of customer choice on January 1, 2001, RRO providers were required to submit annual electricity procurement plans to their regulator for approval. These plans set out the strategies to be used by the RRO providers to purchase their electrical energy requirements and consisted mainly of long-term fixed prices for electricity, commonly referred to as hedges. Customers were charged a regulated rate based on these fixed-price hedges, which resulted in a relatively stable regulated rate. The regulated rate was adjusted on a quarterly basis.

[145] *Regulated Rate Option Regulation*, AR 262/2005, Section 2.

The government introduced a retail electricity market policy in 2005 that changed the manner by which the regulated rate was to be determined. This policy became the *Regulated Rate Option Regulation* and came into effect on July 1, 2006. Under the *Regulated Rate Option Regulation*, RRO providers were required to decrease the hedged portion of their procurement plans by 20 per cent annually beginning on July 1, 2006 and ending on June 30, 2010. Consequently, effective July 1, 2010, the pricing for the RRO is determined using only the projected monthly index electricity price posted by the energy exchange market.[146] The intent of the policy was to have a retail price for the RRO that was more reflective of the prevailing power pool price for electricity. The RRO providers were not allowed to use rate adjustment mechanisms such as true-ups, rate riders or other similar accounts to reconcile their costs for purchasing electrical energy with the revenues collected from customers. The RRO varies month to month, but remains fixed within a month.

Residential, farm and small commercial customers account for approximately 30 per cent of the total electrical energy consumed in the province. Nearly 70 per cent of the total number of residential customers and 50 per cent of the total number of eligible small commercial customers have elected to remain on the RRO rate.[147]

### Competitive retailers

Competitive retailers offer electricity services to customers under an energy contract established by the retailer that states the price for the electricity as well as the terms and conditions of service. Some competitive retailers offer their services to customers throughout Alberta while others restrict their offerings to specific geographical areas. The government of Alberta licenses competitive retailers but does not regulate their prices. Customers can choose a retailer that offers various options including one-year, two-year, three-year and five-year fixed price contracts, floating rates, dual fuel (electricity and natural gas) services, seasonal plans and green energy products (electrical energy generated by renewable sources).

There are a number of competitive retailers offering electricity contracts for residential, farm and small business customers. They are Alberta Energy Savings L.P., Bow Valley Power, Direct Energy, ENMAX Energy Corp., E.NRG Power, Just Energy Alberta L.P., Mountain View Power and Spot Power.[148] Direct Energy Marketing Limited and ENMAX Corporation provide competitive electricity services as well as the RRO service under separate business units. As of October 2010, 27 per cent of the eligible RRO residential customers, 19 per cent of eligible RRO farm customers and 47 per cent of eligible RRO small commercial customers were receiving electricity services from a competitive retailer.[149]

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146 The energy exchange market is operated by Natural Gas Exchange Inc. (NGX).

147 The Market Surveillance Administrator, "Retail Review: Electricity and Natural Gas" (February 13, 2009) page 2, online: MSA http://www.albertamsa.ca/files/Public_Retail_Report_021309(1).pdf.

148 The Alberta electricity retail market is home to companies of many different sizes. Some have been founded and are owned and operated by resident Albertans while others have operations throughout North America.

149 Government of Alberta, Department of Energy, "Statistics Information System Switching Percentage By Group" (January 21, 2011), online: Government of Alberta, Department of Energy, http://www.energy.alberta.ca/electricity/esi/Table1_Electricity_Alberta_ByGroup.pdf. Percentages are based on number of sites, not on total electrical energy consumed.

### Green energy products

Customers have the ability to participate in renewable energy generation programs through services offered by Bullfrog Power Inc., ENMAX Energy Corporation and Just Energy Alberta L.P. When customers enroll in one of these programs, electrical energy will be procured from a certified green energy source or carbon credits are purchased. The intent of the program is to displace the amount of electrical energy that otherwise would be produced from a fossil fuel-based generating plant. In the case of ENMAX Energy Corporation and Just Energy Alberta L.P., the program complements their existing competitive retail services. Bullfrog Power's program is available to customers on the RRO rate as well as on a competitive rate, as they separately invoice customers who subscribe to their program.

### Self-retailers

Self-retailers are customers who procure electricity from the power pool for their own use. Most industrial customers and large commercial customers are self-retailers. A number of self-retailers use specialized service providers to manage the complex electrical energy billing processes, and for their energy settlement and billing data management requirements.

### Smart customer technologies

The promotion of wise energy use is an objective of the Alberta Provincial Energy Strategy. Advanced technology that enables consumers to receive real-time data from the meter at the same time as receiving pricing information from retailers will allow consumers to make informed decisions on the wise use of energy.

Smart customer technologies include home energy management systems and home area networks. Home energy management systems provide intelligence and networking capabilities to consumer appliances and devices. Home energy management systems consist of devices, such as programmable thermostats, home appliances with internet protocol addresses, and applications that monitor and control electrical appliances. The home area network is the communication and information network located inside a residence or building that connects digital devices with one another.[150] Examples of existing home area networks include home entertainment centers, security systems and lighting systems. The home area network could also transmit energy consumption data from the smart meter to in-home displays and appliances on a real-time basis.

The Commission was informed that most residential sites in Alberta have some type of home area network installed that could readily accommodate energy management programs and devices. It was suggested that utilities should partner with communications organizations to deliver additional benefits to the customer.[151] These benefits include the provision of real-time and tangible information to customers through a variety of platforms and methods such as web portals, television and smart phone applications. Customers could use this information to monitor and manage their electricity consumption and lower their electricity bill by reducing or shifting their electricity usage.[152]

[150] See Appendix 7 – Smart metering technologies and related matters.
[151] Transcript, Volume 3, page 585, Mr. Gedeon, TELUS Communication Inc.
[152] Exhibit 88.01, Direct Energy Response to Commission Question 28 and 40.

### Competitive retailing opportunities using smart customer technologies

Residential, farm, and small commercial customers have various choices regarding pricing plans offered by competitive retailers. Smart meters and AMI could provide retailers with the opportunity to offer additional energy management services tailored to the customers` needs and new multi-period pricing plans that include price variations based on the time the electricity is consumed. Other benefits to retailers include increased accuracy in the billing process, potential reductions in customer call volumes and increases in the call center efficiency as consumers become better informed about their electricity consumption behaviour.

It was noted during the Inquiry that dynamic pricing schemes based on the hourly power pool price of electricity may not be widely adopted by customers, even when supported by smart meters and AMI.[153] The complexity may be too great and even the adoption of home energy management systems programmed into the home computer may be inconvenient for customers.

### Policy considerations

Consumers are presently deploying home area network technology for a variety of activities such as to program home entertainment systems, monitor home security systems, and control household activities. This technology is also in use to control temperature and lighting settings and to switch appliances on or off. The technology panels at the Inquiry told the Commission that existing home area networks could be readily extended to integrate energy management programs and applications to control electricity consumption within the home without the use of a smart meter. A competitive market already exists for customers to choose a home area network and energy management program that suits their needs and preferences. However, the availability of usage information directly from the meter in real-time would enhance the effectiveness of these programs by connecting the meter directly to computers programmed to manage the energy use. It is for this reason that a number of jurisdictions have required that smart meters include the ability for customers to gain real-time access to direct their consumption data through connections to the smart meter.

Providing customers with detailed information about their electrical energy usage along with multi-period pricing information which more closely reflects the prevailing pool price at a given time will permit customers to better control their energy use and costs. These new opportunities will be complex and not readily understandable for many customers. A number of participants expressed the view that consumer awareness and educational programs will be critically important to foster residential, farm and small commercial customer acceptance of multiple period pricing plans and allow customers to take advantage of the new opportunities.[154] These programs could be initiated by the government or could be left to the retailers wishing to market these programs.

[153] Exhibit 88.01, Direct Energy Response to Commission Question 43.

[154] Participants Response to Commission Question 42: Exhibit 103.01 (AESO); Exhibit 82.02 (CAREA and SAREA); Exhibit 99.02 (AltaLink); Exhibit 100.02 (FortisAlberta); Exhibit 94.02 (General Electric Canada); Exhibit 112.02 (UCA); Exhibit 97.01 (Pembina Institute); Exhibit 102.03 (ENMAX); Exhibit 111.01 (Rick Cowburn).

## Communications, cyber security, standards and privacy

### Cyber security and interoperability standards

Historically, electric utilities did not require sophisticated electronic communications systems to carry on their businesses. Various forms of electronic communications were deployed as new technologies were introduced into the system. In some cases the utilities deployed their own power line carrier systems or wireless communications systems and in some cases used the systems of local telephone companies.

Today, all parts of Alberta's electricity system have some form of electronic communications systems in place, with varying levels of sophistication and security depending on the age and function of the system. Communications systems are made up of a combination of technologies some of which may be owned by the companies and some of which may be leased from third party providers.

The most well developed and sophisticated communications systems in Alberta's electricity industry are deployed in the transmission systems. The AESO and the TFOs have a variety of communications systems and devices utilizing wireless and fiber optic technologies to ensure reliable operation of the AIES. Some portions of the communications networks are owned by the TFOs and some are leased from telecommunications service providers. The communications networks have evolved in order to enable the functioning of the competitive generation market and the introduction and utilization of smart transmission technologies by both the AESO and the TFOs.

The implementation of smart transmission technologies and multiple digital control devices employed throughout the transmission system and the requirements to interconnect with other jurisdictions in North America introduce the possibility of unauthorized access and control that can cause major system outage events and equipment damage. Robust security is required to ensure that the reliability of the grid is not compromised.

Some participants in the Inquiry expressed concerns that increased reliance on internet-protocol-based networks and applications for the utilization of smart grid technologies increase cyber security concerns.[155] Others stated that all modern electronic communications systems are based on internet protocol and that all of the security protection applications available in the computing and telecommunications industries are also available to the electricity industry.[156]

In response to these and other security concerns, operational, technical and security standards are being developed at the international and North American level by recognized and reputable industry organizations. The North America Electric Reliability Corporation (NERC) is responsible for developing reliability standards that provide for the reliable and safe operation of the bulk power system including specific critical infrastructure protection standards to prevent unauthorized cyber and physical access to critical assets and critical cyber assets.

Alberta's *Transmission Regulation*[157] states that the reliability standards of the NERC and the Western Electricity Coordinating Council (WECC) apply in Alberta to the extent that those

[155] Transcript, Volume 2, pages 402 and 444, UCA.
[156] Transcript, Volume 2, pages 245 and 250.
[157] *Transmission Regulation*, AR 86/2007, Section 19(1)(a) and 19(2)(a).

reliability standards are adopted by the AESO. The AESO is required[158] to work with the TFOs, owners of electric distribution systems, generators and affected parties to review and adopt the requirements contained within the reliability standards and to submit the reliability standards to the Commission for approval. The NERC and WECC standards may apply to all market participants but in practice apply to generators, the AESO and the TFOs, and generally not to owners of distribution systems.

The National Institute of Standards and Technology (NIST) in the United States is responsible[159] for bringing together manufacturers, consumers, energy providers, and regulators to develop interoperability standards and protocols to ensure that all smart grid devices and systems are able to work together. The NERC and NIST are jointly developing standards to integrate adequate cyber security protection at all levels (device, application, network and system) of the smart grid and developing interoperability standards to ensure the continued reliability of the bulk power system as new smart grid technologies and systems are developed and integrated with existing systems and networks.

A Canadian task force has been initiated[160] aimed at addressing the harmonization of smart grid technologies and standards at the national and international levels. The guiding principles of the task force are:

- Canada's Smart Grid Task Force should aim to ensure that Canada's needs are reflected in products developed under the Smart Grid initiatives at the International Electrotechnical Commission (IEC)

- make best efforts to leverage national and North American efforts to ensure [Canadian] Smart Grid priorities are identified and incorporated into IEC's work

- avoid national and regional differences, unless these are appropriately identified and understood as necessary[161]

The *Transmission Regulation* in Alberta recognizes the need for adequate security standards to protect the AIES and public security. The AESO, the TFOs and affected parties are required to be fully engaged in the creation and adoption of NERC standards in Alberta. The NERC recently established a Smart Grid Task Force to review reliability impacts of integrating smart grid technology. The AESO stated that it will be monitoring these developments closely to ensure that Alberta-specific requirements can be accommodated with any revised or newly proposed NERC reliability standards.[162] Accordingly, there does not currently appear to be a need for additional policy or further legislation at the provincial level regarding the creation and adoption of security protection standards for the AIES facilities or for smart grid interoperability standards.

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158 *Transmission Regulation*, AR 86/2007, Section 5(3), 5(4) and 19(4)(a).

159 U.S. *Energy Independence and Security Act* of 2007, Section 1305(a).

160 Canadian National Committee to the International Electrotechnical Commission (IEC), Task Force on Smart Grid Technology and Standards (CNC/IEC/TF-SGTS) and associated Resource Group.

161 B. Bryans, B. Lojk, "CNC/IEC Smart Grid Technology and Standards Task Force Presentation" (November 4, 2010), online: Canadian National Committee to the IEC, http://isacc.ca/isacc/_doc/ArchivedPlenary/ISACC-10-44303.pdf.

162 Exhibit 103.01, AESO Response to Commission Question 27.

### Billing and settlement communications systems

Complex billing and settlement processes were developed with the restructuring of the electricity market in Alberta and the resulting need to share meter data.[163] The necessary electronic data transfer standards and systems between the meter, the distribution company, the retailer and the AESO are in place today for industrial and large commercial customers. Electronic data transfer standards and systems are also available for residential and small commercial customers but electronic connections between the meters and the distribution company business offices are not. All of these transfer and standards systems and electronic communications systems can be adapted, enlarged and upgraded to accommodate the introduction of smart meters and AMI along with multi-period pricing plans for residential and small commercial customers.

Despite the well-developed interfaces between billing and settlement systems, electronic communications links from the meter to the distribution company business offices have not been rolled out across the province. These communications links are required both to allow the distribution company to take advantage of the operational benefits made available through smart meters and to make possible the collecting and recording of extensive multi-period pricing information. Whether the government chooses to mandate the roll-out of smart meters quickly or over a longer time period, or chooses to allow the roll-out to proceed in response to competitive market forces, these communications links will have to be established if full smart metering capabilities are to be available.

These communications facilities will not need to have significant bandwidth capability.[164] In addition, there is no need for the distribution companies to deploy facilities that comply with any interconnection standard or protocols for these links if they serve no other function but to connect the meter to the distribution company business office. However, interconnection standards and protocols should be established for these links if they are to interconnect with the retailer. The technologies and facilities capable of providing the connections from the meters to the distribution company business offices are available today from existing cable, telephone and wireless carriers or can be provisioned by the distribution companies themselves. Encryption, firewalls and tiered access systems are available to the distribution companies and other entities in the market today and should be deployed to protect both the integrity of the data carried and transferred over interconnections and the privacy of the customers. However, if smart meters are rolled out by retailers or customers, distribution companies could continue to operate as they do today. The electronic communications links would be established between the meter and the retailer.

In addition to these communications systems, new smart meters will be capable of real-time usage measurement and customers will expect to be able to access that information from their own devices in the home. The National Institute of Standards and Technology (NIST) in the United States has primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems.[165] The AESO can be relied upon to monitor and implement NERC and WECC reliability standards in Alberta. However, there is a need to monitor the progress of NIST and its Canadian counterpart to ensure that the devices and appliances purchased by Alberta

[163] See Appendix 7 – Smart metering technologies and related matters.
[164] Transcript, Volume 2, page 249.
[165] National Institute of Standards and Technology, "Smart Grid Collaborative Site", online: NIST, http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/WebHome.

customers (which are likely to be based on North American or international standards) are compatible with the systems deployed by retailers and technology companies in the province.

## Privacy

The security and interoperability concerns related to the implementation of smart grid technologies are expected to be addressed at the national and international levels. Issues related to privacy and the use of personal information that might be available as a result of the deployment of smart meters will likely need to be dealt with at the provincial level.

There was consensus from participants in the Inquiry that privacy issues must be addressed and considered before the first stages of any smart meter deployment because a smart meter roll-out will result in the collection of large amounts of consumer information. As noted in the Inquiry by Alberta's Information and Privacy Commissioner, human ingenuity being what it is, any information collected about anything will be put to uses other than that for which it was collected.[166]

In Alberta, the collection, use and disclosure of personal information is regulated by three statutes[167] that provide that organizations can collect personal information if they have either consent or legal authority. These collecting organizations can then only use or disclose the information collected for the purpose for which it was collected, or for consistent purposes, unless they get [further] consent.[168]

As to what information might be considered personal information, it is worth noting that there are a number of different customer-specific data sets that may be captured by an advanced metering infrastructure, not all of which may be characterized as personal information under the Alberta legislation. The types of data that may be retrieved include:[169]

- Meter Data – all data captured by/for the AMI system, including interval usage data, voltage/power quality readings, meter event data, acknowledgement/verification of message transmissions or price signals/compliance. Although Customer Data may be accessible by the AMI meter via HAN [home area network] interface, Meter Data does not include customer data.

- Usage Data – Usage Data is the interval energy and demand data captured by the AMI [smart] meter and transmitted to the meter data management system. Usage data is a subset of meter data that does not include voltage readings, meter event data, acknowledgements and verifications.

- Billing Data – all data required for bill calculation, including pricing information, compliance confirmations to demand response pricing signals, net metering data, and distributed resource coordination.

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166 Transcript, Volume 3, pages 524-525.

167 *Freedom of Information and Protection of Privacy Act* (R.S.A. 2000, Ch. F-25), *Health Information Act* (R.S.A. 2000, Ch. H-5) and *Personal Information Protection Act* (S.A.2003, Ch. P-6.5).

168 Transcript, Volume 3, page 525.

169 Illinois Statewide Smart Grid Collaborative, "Collaborative Report" (September 30, 2010), page 147, online: Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/en/ISSGC%20Collaborative%20Report.pdf.

- Customer Data – HAN-level and appliance-level usage and in-premises energy management data not required for AMI system operations, demand response, or distributed resource coordination.

Information and Privacy Commissioner of Alberta Frank Work, QC, indicated a preference that an early first step, prior to smart meter implementation, would be to determine whether the information collected by smart meters and the collecting organizations are subject to Alberta's *Personal Information Protection Act*.[170] This analysis might be impacted by different data management solutions: for example, the scenario of individual utilities collecting, using and disclosing the personal information rather than a centralized data depository as implemented in Ontario.[171] Mr. Work indicated that while one centralized body, such as the Ontario's central meter data management repository, would probably be easier to administer from a privacy standpoint, having separate collectors of this information was manageable but "just means you do more work in terms of education."[172]

The risks of disclosure of this personal information fall generally into two broad categories: concerns about inadvertent disclosure of the information, and concerns regarding intentional disclosure or sale of the information. Some of the potential risks were highlighted in a White Paper prepared by the University of Colorado at Boulder regarding smart grid deployment in Colorado.[173] These ranged from "nefarious" uses, such as establishing when someone is usually away from home or has an electronic alarm system, to gaining information valuable to marketers such as when someone watches television or how much time they spend in front of the computer. This information can also be used to establish usage profiles based on a customer's age, gender, race or ethnicity.

The Office of the Utilities Consumer Advocate (UCA) cited a report released June 16, 2010, by the Information and Privacy Commissioner of Ontario that laid out seven considerations (best practices) dealing with privacy specifically in the smart grid context.[174] Other jurisdictions, such as Illinois,[175] have also attempted to address the scope of matters that should be considered.

Participants in the Inquiry agreed that consumer privacy is a critical issue in the context of smart meters. As noted in the Colorado White Paper: "The potential for data mining and acquiring intimate details about consumer behavior and lifestyle is a reality. These risks may lead to major privacy issues unless a deliberate and thoughtful approach is taken to protect consumer information."[176]

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170 Transcript, Volume 3, page 528.

171 For further detail see Appendix 7 – Smart metering technologies and related matters.

172 Transcript, Volume 3, page 533.

173 K. Doran, F. Barnes & P. Pasrich (eds.), "Smart Grid Deployment in Colorado: Challenges and Opportunities" *University of Colorado at Boulder* (June 2010) page 44, online: Center for Energy & Environmental Security http://cees.colorado.edu/sgreport.pdf.

174 Ontario Information & Privacy Commissioner, "Privacy by Design: Achieving the Gold Standard in Data Protection for the Smart Grid," cited by the UCA (Exhibit 112.02) in Response to Commission Question 55.

175 Illinois Statewide Smart Grid Collaborative, "Collaborative Report" (September 30, 2010), page 147-149, online: Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/en/ISSGC%20Collaborative%20Report.pdf.

176 K. Doran, F. Barnes & P. Pasrich (eds.), "Smart Grid Deployment in Colorado: Challenges and Opportunities" *University of Colorado at Boulder* (June 2010) page 49, online: Center for Energy & Environmental Security http://cees.colorado.edu/sgreport.pdf.

Information and Privacy Commissioner of Alberta Frank Work, QC noted that Alberta has a solid regime of privacy legislation and that it is likely that one of the existing laws would apply. He also suggested that a first step might be to establish a working group of information and privacy officers from the industry, the relevant Government of Alberta departments, the AUC and the Office of the Information and Privacy Commissioner.[177]

## Conclusion

In this Inquiry, the Commission has learned that the evolution of smart grid is, in many ways, simply the evolution of good engineering practices and that not all smart grid technologies will provide sufficient benefits to justify their deployment in all utility companies. The size, customer mix, characteristics of the geographic areas served by utility companies and other factors will determine which technologies will be best suited to each company and its customers. This is the case throughout the electricity system from generation through to meters, retailers and customers.

The Commission has also learned that smart meters, which are the most celebrated of the smart grid technologies, are changing rapidly in response to technological change and competition among meter manufacturers. While prices are declining and meter functionalities are increasing, the changes necessary to take advantage of the new smart meters go well beyond simply replacing the old meters with new ones. New communications systems, billing and settlement systems and data storage systems are required to take advantage of all that the smart meters have to offer. Smart meters will need to be capable of providing real-time electricity usage information to customers in their homes and businesses as well.

Participants in the Inquiry urged caution when considering the pace of change and the potentially high costs of rolling out smart grid technologies, and especially smart meters. They were concerned about experiences in other jurisdictions as well as adopting technologies today that could be quickly outdated leaving customers to pay more than necessary during any transition period. Their message was: "Go slow – but go."[178]

Despite these concerns, Alberta has already made significant progress in the deployment of smart grid technologies. These deployments have already contributed to the achievement of the provincial energy strategy goals of clean energy production, wise energy use and sustained economic prosperity. Smart grid technologies have been deployed and are being deployed by the AESO and the TFOs to integrate wind and other renewable energy sources into the competitive wholesale market without any special incentives or subsidies. Industrial and large commercial customers, who account for approximately 70 per cent of electrical energy consumption in Alberta, are capable of responding to changes in the Alberta power pool prices through the use of meters with smart capabilities and, increasingly, direct connections through the meter to the customers' operations systems. These innovations control energy costs for these customers, enhance the reliability of the electricity system, support integration of renewable energy

[177] Exhibit 181.01, Submission of the Alberta Information and Privacy Commissioner, page 3.
[178] Exhibit 111.01, Cowburn Response to Commission Questions.

resources, contribute to wise energy use and contribute to the economic prosperity of the province.

In many ways, restructuring and the introduction of competition into the electricity market have driven smart grid deployment in Alberta. Competition has driven the adoption of innovations in the integration of renewables and smart metering for industrial customers. It has also prompted the development of electronic communications systems, billing and settlement systems and processes and data storage systems that connect the AESO, retailers and distribution companies to make retail competition work. These systems can be upgraded and enhanced to accommodate new advanced metering infrastructure requirements. As a result, Alberta is well positioned to take the next steps toward the deployment of smart meters and advanced metering infrastructure.

The decision of whether this is the time for those next steps and what they might look like can be informed, at least partially, by the cost-benefit methodology provided by the Commission. Options range from a mandated roll-out of smart meters and advanced metering infrastructure accompanied by mandated multi-period pricing plans to simply allowing competitive markets and good engineering practice to drive the adoption of smart meters for operational purposes and for those customers who want to take advantage of the energy management opportunities made possible by them. This would not mean that there would be no role for the government. At a minimum, the government should be prepared to step in to remove legislative barriers and provide for the development and adoption of policies, standards, processes and rules to facilitate the roll-out of emerging smart grid technologies in Alberta where justified.

Five principles for the development of smart grid policies in Alberta emerged from the Inquiry process.

- Smart grid policies and objectives should be clear, well defined, and articulated prior to smart grid investments being mandated.

- Smart grid policies should maintain and enhance the reliability and quality of electricity service in Alberta.

- Smart grid policies should support the operation and continuation of the competitive generation and retail markets and should not create artificial competitive advantages for one group of market participants over another.

- Smart grid investments should be required to pass a cost-benefit test to protect customers from unnecessary rate increases.

- Competitive market forces should be relied upon to the greatest extent possible to implement smart grid technologies in Alberta.

Participants in the Inquiry are asking that the government articulate its objectives for smart grid in Alberta so that they can move forward to help in achieving them. The five principles, the cost-benefit methodology provided in Appendix 5 and the discussion of the Alberta experience with smart grid development and deployment in Alberta contained in this report are offered to assist the government in its consideration of smart grid objectives and policies for Alberta.

All of which is respectfully submitted.

Dated on January 31, 2011.

**The Alberta Utilities Commission**

| | | |
|---|---|---|
| Willie Grieve<br>Chair | Dr. Moin Yahya<br>Member | Dr. Roy Billinton<br>Acting Member |

# Appendix 1 – Order-in-Council and Inquiry process

## Appendix 1 – Order-in-Council and Inquiry process

***This appendix describes the requirements set out in the Order-in-Council that established the Smart Grid Inquiry and describes the process that the Alberta Utilities Commission used in conducting the Inquiry.***

### Establishment of the Inquiry

The Government of Alberta established the Alberta Smart Grid Inquiry by Order-in-Council[1] on March 25, 2010. Schedule B to the Order-in-Council set out the following Terms of Reference for the inquiry into and report to the Minister of Energy on the Alberta Smart Grid:

"WHEREAS it is the policy of the Government of Alberta to strengthen and modernize Alberta's interconnected electric system to support its goals of clean energy production, wise energy use and sustained economic prosperity;

WHEREAS the Government of Alberta is interested in implementing policies supporting the development and deployment of smart grid technology in support of achieving these goals;

WHEREAS the smart grid can be characterized as the modernization of Alberta's electricity system, through the application of advanced control and information technology, to meet the future needs of the province, and the characteristics of the smart grid include, but are not limited to:

1 Inclusivity: the smart grid applies to the entire electricity system including generation, transmission, distribution, and consumers;

2 Reliability: The smart grid provides enhanced ability to warn of and identify potential failures and take remedial action before users are affected, that is, the smart grid self-heals;

3 Security: The smart grid withstands cyber attacks;

4 Environmentally Friendly: The smart grid reduces the environmental impact of the Alberta electricity system through the application of advanced technology that will provide for the integration of more renewable generation, more effective load management, and better information for consumers;

5 Accessibility: Electricity market participants must have access to all necessary information to make informed choices;

WHEREAS in order to permit the Government of Alberta to consider a full range of options on all issues relating to the smart grid, it is desirable that a smart grid review be conducted by the Alberta Utilities Commission (AUC);

[1] Exhibit 6.01, O.C 93/2010.

THEREFORE the following terms of reference apply in respect of the inquiry into and report to the Minister of Energy on the Alberta Smart Grid:

(a) the AUC shall inquire into the following matters for the purpose of gathering information with respect to those matters:

(i) the current status of smart grid development in Alberta;

(ii) the status of smart grid deployment in other jurisdictions;

(iii) the guiding principles, objectives and goals for developing the smart grid in Alberta;

(iv) the enablers and barriers to the deployment and development of the smart grid;

(v) the functionality requirements for the smart grid in Alberta, including standards such as those required for the interoperability in the exchange of information;

(vi) the method of assessing costs and benefits of smart grid-related expenditures;

(vii) the necessary courses of action to develop and implement the smart grid, including defining the roles for all the potential market participants;

(viii) the regulatory approach to consider smart grid investments including the extent to which competitive markets can be relied upon to deliver the smart grid;

(ix) other associated issues as required;

(b) in conducting the inquiry the AUC must consult with members of the Alberta electricity industry and other relevant parties;

(c) the AUC shall report to the Minister of Energy in relation to the matters referred to in clause (a);

(d) the AUC's report

(i) must not make recommendations but shall, through its analysis of the evidence on the record of the inquiry and review, provide findings and pros and cons on various issues as it deems appropriate, and

(ii) is expected to be submitted to the Minister within 8 months of the date on which the Order in Council to which this Schedule is attached was made, and must be submitted no later than January 31, 2011."

## Inquiry process

The Commission panel assigned to the Smart Grid Inquiry consisted of Willie Grieve, Chair of the Commission and Chair of the panel; Dr. Moin Yahya, Commission Member; and Dr. Roy Billinton, Acting Commission Member.[2]

Notice of the Smart Grid Inquiry was issued by the Commission on April 20, 2010.[3] The notice was advertised in the Calgary Herald, the Edmonton Journal, the Red Deer Advocate and the Lethbridge Herald on April 26, 2010. The notice was also emailed to the Commission's electric distribution list and bulletin list.

In the notice, the Commission established a process and timelines to allow for written submissions, written reply submissions and an opportunity for public proceedings. The notice also specified five parties whose participation was considered essential to the inquiry[4] and were thus directed to participate. The notice also set out brief guidelines for the recovery of costs by participants.

The Commission also attached 59 questions to the notice and requested that in preparing their written submissions, participants answer all the questions from their perspective. The questions posed by the Commission addressed definitional matters, issues surrounding the deployment of a smart grid in Alberta, standards and other functionality requirements, the costs and benefits of a smart grid, market participation in the smart grid, pricing considerations and other policy considerations.

Fifty-eight participants filed statements of intent to participate in the Inquiry (see list in Appendix 8 – List of the participants in the Inquiry). These participants included representatives from all areas of the Alberta electric system including generation, transmission, distribution (including rural electrification associations), retail and the Alberta Electric System Operator, along with consumer and environmental advocacy groups, various municipalities, interested individuals, vendors of smart grid related products and services and the Office of the Information and Privacy Commissioner of Alberta.

The Commission received written submissions from 38 participants, many of which included detailed responses to the 59 questions posed by the Commission. Written reply to other participants' submissions was also provided for, and nine participants took advantage of the opportunity to reply.

The Commission issued eight follow up questions to participants on August 13, 2010, in order to obtain more detail on certain issues and to explore other areas that had not been addressed in participants' responses. Fourteen participants responded to the supplemental questions. The

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[2] Order-in-Council 165/2010 dated May 13, 2010, nominated Dr. Roy Billinton as a person who may be selected by the Chair of the Alberta Utilities Commission as an acting member of the Commission for a term to expire on March 31, 2011.

[3] Exhibit 5.01, AUC Notice of Inquiry – Regulatory Process for Alberta Smart Grid Inquiry.

[4] AltaLink Management Ltd., ATCO Electric Ltd., ENMAX Power Corporation, EPCOR Distribution & Transmission Inc. and FortisAlberta Inc.

Commission also directed certain specific questions regarding Ontario's "Smart Metering Entity" to Ontario's electric system operator on September 8, 2010, responses to which were provided by letter dated October 4, 2010.[5]

From October 4 to October 8, 2010, the Commission held oral proceedings in both Calgary and Edmonton. These oral proceedings were intended to allow participants to summarize or expand upon their written submissions, as well to provide the Commission panel with an opportunity to question participants to obtain a better understanding of their submissions. Each registered participant was allotted a period of time in which to make an oral presentation and then was subject to questions by the Commission panel. Nineteen participants took part in the oral proceedings that occurred over two days (October 4 and 6) in Calgary, and 10 parties participated in the session held in Edmonton on October 8, 2010.

Following the oral proceedings, the Commission issued a further request for information on November 18, 2010 to certain owners of electric distribution systems in order to better understand current industry practice regarding the handling of meter data.

A number of smart grid related reports from other jurisdictions were introduced in the public domain after the oral proceedings were concluded. These reports, along with other print resources referred to by the Commission in preparing its report, were placed on the record of the proceeding on January 31, 2011.

The Commission provided its written report to the Minister of Energy on January 31, 2011.

[5] Exhibit 187.01, Ontario ISO Correspondence, letter dated October 4, 2010.

# Appendix 2 – Overview of the Alberta electricity market: design, structure and participants

## Appendix 2 – Overview of the Alberta electricity market: design, structure and participants

***This appendix briefly describes the design and structure of the Alberta electricity market and discusses the roles and responsibilities of various participants.***

### Design and structure

Alberta's competitive model for electric supply is referred to as an 'energy-only' market. In this model, generators recover their costs through payments from the power pool, the ancillary services market, the forward market,[1] or through bilateral contracts. In an energy-only market, the power pool price is an important signal as it affects short term futures prices which impact prices for all load and projected revenue streams for generators. In principle, if supply is short, energy prices can compensate peaking units or incent new capacity because the market clearing price will be very high. Sustained high prices will motivate investors to build new capacity. On the other hand, if generators overbuild, prices in the energy-only market will be too low to support fixed and variable generator costs and units will shut down or new supply will be discouraged. In short, the energy-only market is the primary mechanism in Alberta to compensate generators and incent capacity additions. Much of Alberta's electricity is priced through bilateral contracts; however the power pool price influences short term bilateral contract pricing and near term futures prices. Long-term prices are driven by market fundamentals such as demand growth, anticipated weather, natural gas prices and planned generation outages.

The price is set through economic dispatch of price and quantity offers by generators to the power pool.[2] These pairs are ranked by the power pool and placed in a merit order. The system controller calls on generators according to their place in the merit order to meet real-time demand. Every minute, the last generator dispatched in the merit order 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 settled pool price. As a simplistic example, if Generator A was dispatched for 30 minutes at $30 and Generator B was dispatched for 30 minutes at $50, the pool price would settle at $40 for the hour. The annual average hourly price is $51.37 per megawatt hour (MWh) for 2010[3] as compared to $48 per MWh in 2009 and $90 per MWh in 2008.[4]

A secondary market exists to procure operating reserves and ancillary services from generators and it operates separate from the power pool. Generators and large industrial customers may also offer their capability (generation capacity or the ability to curtail load) to the AESO as reliability services or into an operating reserves market which is operated by the AESO to ensure that

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1 For further discussion on forward markets see: The Market Surveillance Administrator, "Financial Electricity Market Report" (April 9, 2010), online: MSA, http://albertamsa.ca/files/Financial_Electricity_Market.pdf.

2 The Alberta Electric System Operator, "Determining the Wholesale Market Price for Electricity" (September 2006), online: AESO, http://www.aeso.ca/downloads/fastfacts_det_market_5_may06.pdf.

3 Year to date to December 21, 2010.

4 For more background on Alberta's wholesale electricity market, see: The Market Surveillance Administrator, "Alberta Wholesale Electricity Market" (September 29, 2010), online: MSA, http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf.

generation and load are continuously and instantaneously balanced.[5] Operating reserves are discussed in more detail in Table 1.

The hourly pool price is the only price signal available in the Alberta market to incent the construction of new generation. Therefore capacity payments, locational pricing, day ahead, hour ahead or bilateral markets design features are not employed in Alberta.

As noted previously, many of the generators in the province have contracted their capacity long term and therefore are not exposed to the hourly settled pool price. Some entities are contracted for up to 80 per cent of their generation portfolio.

## Participants

### *Alberta Electric System Operator*

The Independent System Operator (operating as the Alberta Electric System Operator or AESO), is a not for profit corporation established under the *Electric Utilities Act*. The AESO is responsible for overall coordination of grid operations, for planning and arranging for enhancements to the transmission system and for promoting a fair, efficient and openly competitive market for electricity in Alberta. The AESO is also responsible for managing and recovering the costs of transmission line losses, contracting with individual transmission facility owners to provide transmission services, and developing province-wide tariffs to provide for open and non-discriminatory access to the transmission system.[6]

The AESO manages and oversees a number of activities that contribute to the safe, reliable and economic operation of the interconnected electric and wholesale markets. These activities include: generation dispatch, system voltage control, procurement and management of ancillary services, generation and transmission outage coordination, intertie scheduling, and direction of system restoration during emergencies.

The AESO is responsible for assessing the current and future needs of market participants[7] including planning[8] the capability of the transmission system to meet those needs and arranging for necessary enhancements to the transmission system to maintain system reliability and support a fair, efficient and openly competitive market in Alberta. The AESO must also ensure that

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[5] For in-depth discussion on the market, see: The Market Surveillance Administrator, "Operating Reserves Procurement – Understanding Market Outcomes" (September 16, 2010), online: MSA, http://albertamsa.ca/files/Operating_Reserves_Procurement_Report_091609.pdf.

[6] The Alberta Electric System Operator, online: www.aeso.ca.

[7] Section 1(1)(ee) of the *Electric Utilities Act* defines a market participant as: (i) any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services, or (ii) any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or ancillary services.

[8] Section 10 of the *Transmission Regulation*, provides planning and operational direction and directs the AESO to prepare and maintain a 20-year Transmission System Plan.

interconnections to neighbouring jurisdictions are capable of operating to their path rating[9] to import and export electricity and to plan future interconnection capacity.

The AESO plays a crucial role in creating and managing the operation of a competitive power market. By law[10] all electric energy entering Alberta's system must be bought and sold through the power pool, which is operated by the AESO. To access the pool, all market participants must have a system access agreement with the AESO. The AESO ensures this access is provided in a manner that is fair, efficient and open to all market participants. The AESO also carries out the financial settlement for all electric energy exchanged through the power pool.[11] There are over 200 participants in Alberta's power pool and the transactions of all electric energy bought and sold in the province totaled over $5 billion in 2009.[12]

The AESO is responsible for procuring ancillary services and for managing and recovering the costs for the provision of ancillary services. Ancillary services are services required to ensure that electricity can be transmitted reliably, efficiently, and securely across Alberta's interconnected electric system. The AESO uses competitive processes to procure ancillary services except where there is a location specific need and in these circumstances only certain generators are eligible to provide these services. Ancillary services include operating reserves, transmission must run services, black start, and load shedding services.[13]

Operating reserves are generating capacity that the AESO can dispatch, or load that can be reduced on short notice to continuously and instantaneously match supply and demand and maintain reliable operation of the power grid. The AESO manages a secondary market to procure and dispatch operating reserves. Generators and loads may offer their capability into the operating reserves market providing they comply with the rules and technical performance obligations established by the AESO.

Transmission must run services is generation required to be online and operating at specific levels in particular parts of the AIES to provide support for local transmission infrastructure which is insufficient to supply local demand in a reliable manner. The AESO contracts with generators in areas where transmission must run services are required.

Black start services are provided by generating units that are able to restart their generation facility without an outside source of power. In the event of a system-wide blackout, black start service providers are called upon to re-energize the transmission system and provide start-up

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**9** Path rating is defined in Section 1(1)(i) of the *Transmission Regulation* as the rating of capacity to transfer electric energy assigned to a transmission facility when it was placed in service and rated in accordance with reliability standards in effect at that time.

**9** *Electric Utilities Act*, Section 17.

**10** *Electric Utilities Act*, Section 18(2).

**11** *Electric Utilities Act*, Section 17.

**12** The Alberta Electric System Operator, "Market" (May 2010), online: AESO, http://www.aeso.ca/market/153.html.

**13** The Alberta Electric System Operator, "Ancillary Services", online: AESO, http://www.aeso.ca/market/5093.html.

power to generators who cannot self-start. The AESO contracts with generators in areas where black start services are required.

Load shedding services are services provided by large industrial customers to instantaneously and automatically reduce demand when an unexpected system event occurs. These services can be used by the AESO to respond to unexpected system events and also to increase the transfer capability of transmission interconnections with other jurisdictions. The AESO contracts with large customers of electricity to provide load shedding services. A summary of the services currently provided by large customers is shown in Table 1.

The AESO has authority to make ISO rules, as well as to set reliability standards, operating procedures, criteria and processes respecting power pool operation, interconnection practices, coordination of outage schedules, and planning and arranging for upgrades to the transmission system. The AESO works with generation, transmission, distribution owners and market participants on the development of these ISO rules, standards and procedures.

Market participants must comply with ISO rules and reliability standards.[14] ISO rules are subject to regulatory oversight by the Commission on a complaint basis.[15] Market participants may also file complaints with the Commission regarding the conduct of the AESO.[16]

### *Market Surveillance Administrator*

The Market Surveillance Administrator (MSA) is created under the *Alberta Utilities Commission Act*[17] with a broad mandate including surveillance, investigation, and enforcement to help ensure fair, efficient, and openly competitive electricity and natural gas markets in Alberta.

The main activities of the MSA include monitoring market participants to ensure rules and reliability standards are complied with; investigating matters brought to the attention of the MSA through complaint or referral; reviewing the conduct of market participants; assigning financial penalties to confirmed breaches of rules.[18]

The MSA can bring applications before the Commission to adjudicate breaches of rules, regulations, reliability standards or any other market related matters within its legislated authority. Complaints regarding the conduct of the MSA may also be adjudicated by the Commission.

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[14] *Electric Utilities Act*, Section 20.8.
[15] *Electric Utilities Act*, Section 25.
[16] *Electric Utilities Act*, Section 26.
[17] *Alberta Utilities Commission Act*, S.A. 2007, Ch. A-37.2, Part 5.
[18] See MSA website for further detail at www.albertamsa.ca.

**Table 1: Load customer participation in reliability products**

| Program | Description | Volume |
|---|---|---|
| Load Participation in Supplemental Reserves (SUPL) | • Participates in the supplemental reserves market<br>• Required to reduce consumption within 10 minutes of being directed<br>• Used in loss of supply shortfall situations (part of contingency reserves for the AIES)<br>• SUPL participants cannot participate in LSS (and vice-versa) | Approximately 60 MW currently active in the market |
| Load Shed Service (LSS) | • To support increased import capacity on the BC tie<br>• Load breakers tripped by relay if AIES frequency drops below 59.5 Hz (may occur when BC tie trips at high imports), also can be manually curtailed<br>• Used in supply shortfall situations<br>• LSS loads may be price responsive | Approximately 100 MW contracted (will vary depending on conditions) |
| Import Load Remedial Action Scheme (ILRAS) | • Legacy product<br>• When armed, ILRAS aids in supporting increased import capacity on the BC intertie<br>• Armed only during supply shortfall procedures<br>• Load breakers are tripped by relay should the intertie trip with high imports<br>• Unavailable when there is lightning in the area | 200 – 400 MW (system emergencies only) |
| Demand Opportunity Service (DOS) | • Temporary, interruptible class of transmission service that can apply to a load increase that exceeds a customer's DTS Contract Capacity<br>• Used in supply shortfall and transmission constraint situations<br>• Term, 1 hour, and 7 minute products available | Approximately 100 MW (will vary depending on conditions) |
| Voluntary Load Curtailment Program (VLCP) | • Have agreed to be cut prior to firm load reductions<br>• Used in supply shortfall procedures<br>• Manual direction (phone) | Kilowatts (negligible) |
| Under-Frequency Load Shedding Scheme (UFLS) | • Safety net for extremely large loss of generation<br>• WECC requirement<br>• Set at a variety of frequency levels | Roughly 50% of load |

Source: The Alberta Electric System Operator, "Alberta Demand Response Initiative Discussion Paper" (October 22, 2009), page 17, online: AESO, http://www.aeso.ca/downloads/Demand_Response_Discussion_Paper_-_Final_(3).pdf.

### *Balancing Pool*

The Balancing Pool is a corporation established under the *Electric Utilities Act*[19] to manage certain generation assets[20] in the province as a result of the restructuring of the industry. The Balancing Pool has two primary roles:[21]

1. to manage the financial accounts arising from the transition to a competitive generation market on behalf of electricity consumers
2. to meet any obligations and responsibilities associated with both sold and unsold Power Purchase Arrangements

Each year the Balancing Pool is required to forecast its revenues and expenses to determine any excess or shortfall of funds as a direct result of managing the power purchase arrangements and the management of the financial accounts holding the monies collected in relation to the generation assets.[22] On an annual basis, the Balancing Pool then determines a power bill rebate that electricity consumers will be receiving per megawatt of consumption, funded by the monies they manage.[23]

## Generation in Alberta

Alberta's generation market is deregulated and together with open and non-discriminatory access to the transmission system, is structurally intended to accommodate all forms of generation. All generation, whether connected to the transmission or the distribution system, may participate in the power pool.

There are currently four main types of generation in Alberta: coal-fired, natural gas-fired, hydro and wind. Coal is the most common fuel source for generation of electricity, with coal-fired generation accounting for about 46 per cent of installed capacity and roughly 59 per cent of total electric energy production in 2010.

Figures 1, 2 and 3 below show the current installed capacity, electric energy production by fuel source and annual utilization factors by fuel type:

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19 *Electric Utilities Act*, Section 75.

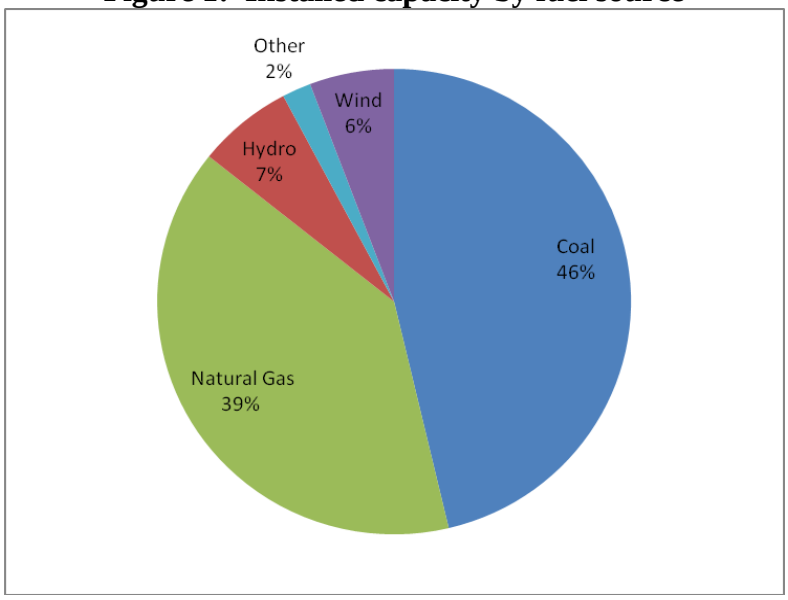
20 *Electric Utilities Act*, Section 85(2): In this section, "generation assets" means (a) power purchase arrangements held by the Balancing Pool that include the right to exchange electric energy and ancillary services, and (b) agreements or arrangements derived from power purchase arrangements held by the Balancing Pool that include the right to exchange electric energy and ancillary services.

21 The Balancing Pool, online: http://www.balancingpool.ca/

22 *Electric Utilities Act*, Section 82.

23 Balancing Pool, online: www.balancingpool.ca.

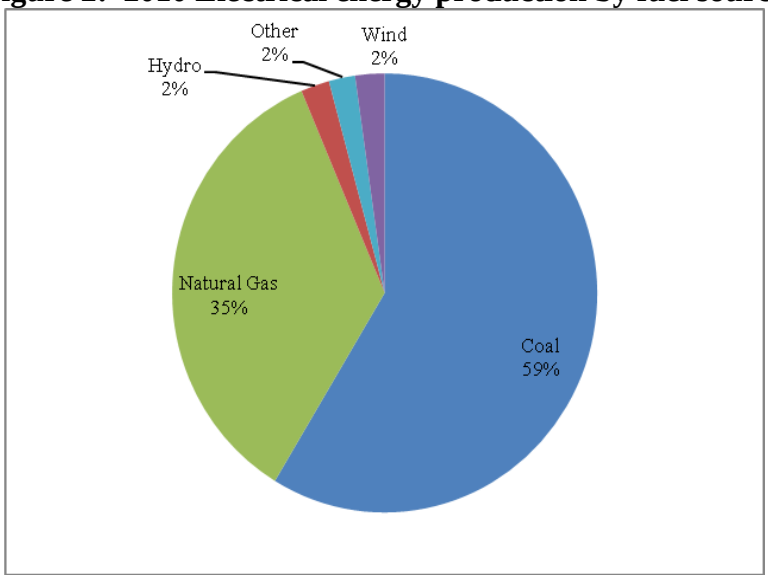
**Figure 1: Installed capacity by fuel source**




Source: AESO, Install capacity reported as maximum capacity rating, Current Supply Demand Report, (January 2011).

Natural gas-fired generation accounted for another 35 per cent of total energy generation in 2010, while hydro, wind and other generation made up the remainder.

**Figure 2: 2010 Electrical energy production by fuel source**



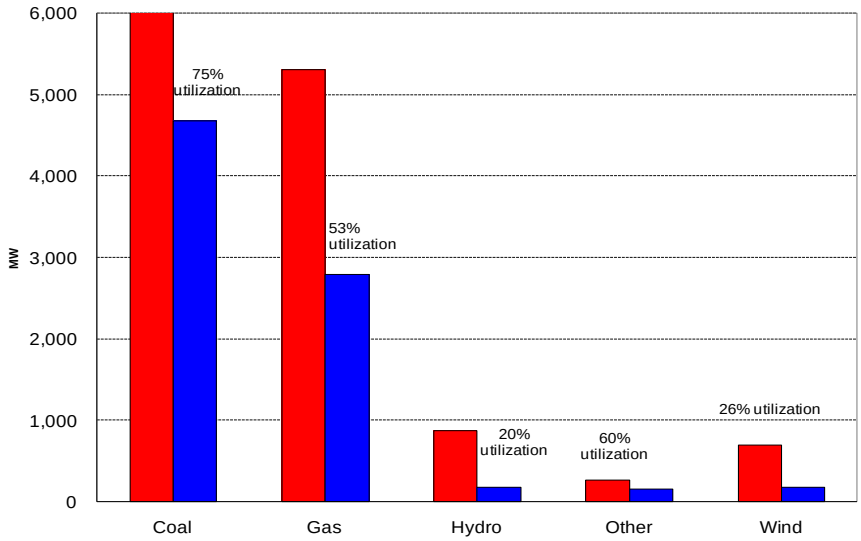

Source: AESO, total net generation (TNG), Current Supply Demand Report

Coal is the base-load fuel in Alberta: these units tend to run constantly as taking them off-line takes time and is costly in terms of future maintenance. The average age of coal units in Alberta

is 28 years. The share of total production contributed by coal-fired units has been gradually shrinking, largely due to increasing natural gas-fired production.

Natural gas-fired generation in Alberta is generally of two distinct types: peaking and cogeneration. Peaking units typically have lower utilization rates as they generally only run during high demand or peak periods.

**Figure 3: Annual utilization by fuel type, 2010**




Source: AESO, average annual maximum capacity rating (MCR), total net generation (TNG), Current Supply Demand Report.

Roughly 70 per cent of the natural gas-fired capacity in Alberta is cogeneration units. Cogeneration is the simultaneous production of electricity and heat using a single fuel source. Cogeneration is typically used in Alberta to support bitumen production from oil sands projects or in upgrading facilities. These facilities tend to have a high utilization rate, as they are run to meet industrial steam requirements and to produce electricity.

Hydro production in Alberta is very dependant on rain and snowfall, as these units are run-of-river with very little storage capacity. In addition to energy production, these units also provide a large portion of total operating reserves required in Alberta.

Wind generation supplied just over two per cent of the total electric energy produced in Alberta in 2010. The market share of wind generation has been increasing rapidly, as the majority of the wind capacity in Alberta has been built in the past five years. Currently there is approximately 780 MW of wind generation installed, achieving on average a 30 per cent capacity factor annually.

### *Role of the AESO – generation*

Generators in the province are allowed to locate wherever they choose and the AESO has responsibility for providing open and non-discriminatory transmission access to all forms of generation, wherever it is situated.[24] In addition, the AESO has the responsibility for planning and arranging for upgrades to the transmission system needed to connect generation to the market.[25] There is a generation queue that the AESO establishes based on the best information available from the generators that want to locate in the province. Generators pay for the cost of local facilities that connect to the grid and pay an additional refundable contribution that varies depending where they locate in the system. The costs of transmission facilities and ancillary services are recovered from customers through the ISO tariff.[26]

### *Micro-generation*

In Alberta, micro-generation is defined as being the generation of electric energy from a generating unit with a total nominal capacity of one megawatt (one MW) or less and is connected to the distribution system.[27] Micro-generation units must produce electricity using a renewable, environmentally friendly fuel source such as solar panels, small-scale hydro, wind, biomass, micro-cogeneration and fuel cells. The electric energy output is intended to meet all or a portion of the customer's electricity needs and customers who generate their own electricity will be credited for any excess electric energy sent into the distribution system through a contract price, a regulated rate or a power pool price. Owners of electric distribution systems are responsible to provide connection services for small micro-generators, to install the bi-directional cumulative or interval meter, as well as to collect the data from the meters.

### *Distributed generation*

Distributed generation may be defined as small-scale power generation, typically in the range of three to 10,000 kW, that can connect to a distribution system, operate within distribution voltage levels and provide electricity close to the point of consumption. Distributed generation technologies generate electricity from fuel on site and the fuel type is not necessarily from renewable sources. Generation technologies used in distributed generation include photovoltaics, microturbines, internal combustion reciprocating engines, combustion turbines, wind generators and fuel cells that may be situated at residential, commercial and industrial sites. Distributed generation can be used to generate a customer's entire electricity supply, to reduce peak demand or "peak shaving;"[28] for standby or emergency generation; as a green power source or for increase reliability of the distribution system. The distributed generation owner is responsible for installing the meter(s) and collecting the data. The electricity sent to the grid is paid for at the hourly power pool price.

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24 *Electric Utilities Act*, Section 29.
25 *Transmission Regulation*, Section 15(1)(e) and (f).
26 *Electric Utilities Act*, Section 30.
27 See *Micro-generation Regulation*, Section 1(1)(e),(g),(h) and(n).
28 Peak shaving is the reduction of the amount of electricity consumed for some period of time, generally during a period of high demand. This can be accomplished through curtailment, load shifting or by self-generation.

In the industrial sector, distributed generation is a relatively mature technology and can include large amounts of cogeneration (hundreds of MWs). It is used as a way to enhance the production processes. For instance, oil sands producers recapture the heat after it has been used in the oil upgrading process and use it to generate electricity. The excess electricity not used on site is sold to the power pool.

## Transmission facilities in Alberta

### *Overview of Alberta Interconnected Electric System*

The transmission system in Alberta covers a wide geographic area and is an integrated system of 500-kilovolt (kV), 240-kV, 144-kV and 69-kV transmission lines and substations that deliver electric power from major generating facilities to load centers. The transmission system delivers electricity generated from coal, natural gas, hydro, wind and other renewable generation sources directly to large industrial customers and, through the distribution system to homes, offices and commercial sites. The transmission system enables electricity transfers across the province and to and from other jurisdictions through interconnections.

In general, the transmission system links industrial demand, cogeneration, and base-load electricity generation in the northern part of the province to major load centres in Edmonton and Calgary. Most peaking generation is located in the central or the southern parts of the province, while existing hydro and wind generation is primarily located in the southern part of the province.

As described in the AESO's current Long Term Transmission Plan,[29] there are four important electricity hubs on the AIES:

> Southern Hub: This hub is central to development of wind generation potential in southeastern Alberta, and it is also likely to be central to new interties with provinces to the east and the U.S. to the south.
>
> Calgary Area Hub: This hub serves the major load centre of the City of Calgary and will also receive wind energy from the south and southwestern parts of the province. This hub is already connected to B.C. and further interties to B.C. or the U.S. are possible.
>
> Heartland Hub NE of Edmonton: This hub is a growing industrial area with substantial projected load growth and the potential for development of low-emission generation such as hydro generation in northeastern Alberta. The demand for power at Heartland is driven by the extraction, upgrading and refining of bitumen from the oilsands into synthetic crude. The Heartland hub is a gateway to load growth and hydro and other generation development in northeastern Alberta, and a possible connection to interties to the east and north.

[29] The Alberta Electric System Operator, "AESO Long-Term Transmission System Plan" (2009), page 4, online: AESO http://www.aeso.ca/downloads/AESO_LTTSP_Final_July_2009.pdf.

Wabamun Lake/Edmonton Hub: This hub is central to a large portion of Alberta's existing generation, and coal-fired base-load generation in particular, and a gateway to generation and interties in the northwest.

The *Transmission Regulation* requires the AESO to restore the transfer capability of the existing interties to their rated capability.[30] Alberta's Provincial Energy Strategy provides for the adoption and implementation of a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta as well as to facilitate development of additional wind generation.[31] Alberta currently has two interties with other jurisdictions, British Columbia (B.C.) and Saskatchewan, to facilitate exchanges of power between jurisdictions. The B.C. intertie is rated at 1,200 MW for imports and 1,000 MW for exports, and the Saskatchewan intertie is rated at 150 MW for both imports and exports. The actual operating limits of the B.C. and Saskatchewan interties can be below their rated capacity due to technical constraints. Alberta's first merchant intertie, the Montana Alberta Tie, is a 230-kV 345 kilometre transmission line that is being constructed between Lethbridge and Great Falls, Montana. When completed in 2011, it will be the first direct connection between Alberta and the U.S. and this intertie will provide an alternate source of energy exchange between Alberta and the northwest U.S.[32]

The AESO is currently reviewing the development of new interties and examining a range of initiatives to enhance the capability of the existing interties including upgrades (DC converters on the Alberta-B.C. intertie) or reconfiguration of existing transmission lines and procurement of contracted load services from large customers and generator automatic control schemes.[33] Large industrial customers have provided proposals to the AESO to allow contracted load to be automatically interrupted to support additional imports on the B.C. intertie.[34] The AESO is also reviewing intertie rules, tariffs, and energy scheduling practices to allow more flexible balancing between regions and access to a larger pool of balancing resources which could support the large-scale integration of variable generation.[35]

### *Role of transmission facility owners*

In order to ensure that generators and market participants can access and supply electricity through the transmission system regardless of who owns the power lines, the AESO contracts with the TFOs to use their transmission assets to provide fair and open access to the system. The TFOs provide transmission services in accordance with AESO rules and standards and these

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30 *Transmission Regulation*, Section 16.

31 Exhibit 4.01, Alberta's Provincial Energy Strategy, page 44.

32 ERCB ST98-2010, "Alberta's Energy Reserves 2009 and Supply/Demand Outlook 2010-2019" (2010) pages 9-8 and 9-9, online: The Energy Resources Conservation Board http://www.ercb.ca/docs/products/STs/st98_current.pdf.

33 K. Gunsch (prepared by K. Aksomitis), "Intertie Restoration" (October 7, 2010), online: The Alberta Electric System Operator, http://www.aeso.ca/downloads/Intertie_Restoration_Recommendation_Paper_Final.pdf.

34 The Alberta Electric System Operator, "RE: AESO Request for Expression of Interest in LSSi" (January 18, 2010), online: AESO http://www.aeso.ca/downloads/LSSi_Release_Jan_18_2011.pdf.

35 K. Gunsch (prepared by D. McCrank), "Intertie Framework" (October 7, 2010), online: the Alberta Electric System Operator http://www.aeso.ca/downloads/Intertie_Framework_Recommendation_Paper_Final.pdf.

terms and conditions of service are approved by the Commission. The *Electric Utilities Act* requires the TFOs to maintain their systems at a level suitable to ensure safe and reliable delivery of electricity[36] and they must comply with AESO reliability standards and ISO rules.[37]

Transmission facility owners[38] have specific obligations regarding the design, operation, maintenance, performance, integrity and capability of their transmission assets and the day-to-day operation of their portion of the transmission system. There are seven transmission facility owners in Alberta with the two largest being AltaLink Management Ltd. and ATCO Electric Ltd. The remaining five are ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., TransAlta Corporation, the City of Lethbridge and the City of Red Deer. Collectively, these entities own approximately 25,000 kilometres of transmission lines and over 580 substations.

### *Ownership of transmission lines and substations in Alberta*

The following table provides the approximate length of transmission lines and number of substations associated with each transmission facility owner:

**Table 2: Alberta transmission lines, substations and owners (lines in kilometres)**

| Voltage | Circuit | AltaLink | ATCO | ENMAX | Red Deer | EPCOR (aerial) | EPCOR (under-ground) | Suncor | TransAlta |
|---|---|---|---|---|---|---|---|---|---|
| **138 kV** | *Double* | 285 | 320 | 11.2 | 8.2 | - | - | 6 | - |
| | *Single* | 6114 | 4842 | 193.7 | 24 | 17.6 | - | 56 | 219.8 |
| **240 kV** | *Double* | 3072 | 1467 | 4.1 | - | 19.6 | - | 140 | 40.46 |
| | *Single* | 4543 | 1243 | | - | 12.4 | 19.5 | - | 43.1 |
| **500 kV** | *Double* | 0.8 | - | - | - | 4.2 | - | - | - |
| | *Single* | 296 | - | - | - | - | - | - | 8 |
| **Other** | *Double* | 7 | - | - | - | - | - | - | - |
| | *Single* | 809 | 1324 | - | - | 19.2 | 86.5 | - | 21.23 |
| No. Substations | | 278 | 152 | 37 | 3 | 30 | | 85* | 3 |

Source: Participants' written responses to Commission Questions 6 and 7, Appendix A, Exhibit 3.01
Notes:

- EPCOR circuits include overhead and underground transmission.
- 'Other' refers to 69/72-kV for AltaLink and TransAlta and 72-kV for all others.
- The City of Lethbridge owns 5 substations, no transmission lines.
- ENMAX 4.1 km are 138/240-kV lines.

*Suncor has reported transmission lines and facilities situated on its own sites.

36 *Electric Utilities Act*, Section 39(1).
37 *Electric Utilities Act*, Section 20.8.
38 Transmission facility is defined in Section 1(1)(bbb) of the *Electric Utilities Act* and includes transmission lines energized in excess of 25,000 volts, transformers, and substations.

***Bulk electric system and critical transmission infrastructure***

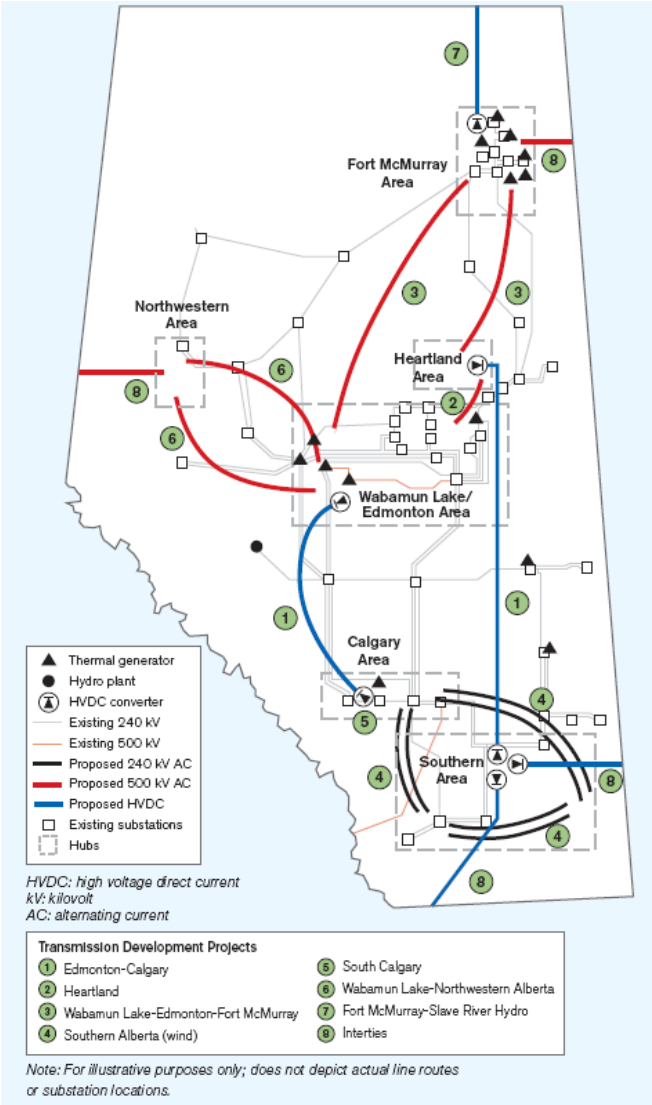
Alberta's Provincial Energy Strategy established certain outcomes respecting transmission infrastructure including comprehensive upgrades to the province's transmission system, use of high voltage direct current technology, building transmission to zones of renewable generation and restoring the capacity of existing interconnections and building new interties.

Consequently, the *Electric Utilities Act* was amended to include a Schedule which designates certain transmission facilities as critical transmission infrastructure. These transmission facilities are described as: two HVDC transmission facilities between the Edmonton and Calgary regions; one double circuit 500-kV alternating current transmission facility connecting to the 500-kV transmission system on the south side of the City of Edmonton and to a new substation to be built in the Gibbons - Redwater region; a 240-kV substation to be built in the southeast area of the City of Calgary; and two single circuit 500-kV alternating current transmission facilities from the Edmonton region to the Fort McMurray region.[39]

The following AESO figure shows the existing system together with critical infrastructure projects and other proposed projects:

[39] *Electric Utilities Act*, Schedule, "Critical Transmission Infrastructure."

**Figure 4: Bulk electric system and critical transmission infrastructure**[40]




Source: AESO Long-Term Transmission System Plan 2009

## Distribution systems in Alberta

Electric distribution systems deliver electricity from the transmission grid to consumers in homes, offices and commercial sites. A distribution system may include medium-voltage (less than 25-kV) power lines, substations and pole-mounted transformers, low-voltage (less than one-kV) distribution wiring and electricity meters. The role of the substation is to transfer electrical energy from transmission lines to distribution system areas. Distribution substations typically contain switches, transformers and reclosers or circuit breakers to protect the

[40] The Alberta Electric System Operator, "AESO Long-Term Transmission System Plan" (2009), online: AESO http://www.aeso.ca/downloads/AESO_LTTSP_Final_July_2009.pdf.

distribution circuits as well as power factor correction capacitors and voltage regulators. Transformers perform the critical function of stepping down voltages throughout the distribution system.

In Alberta, the distribution of electricity is provided by investor-owned and municipal-owned distribution utilities and rural electrification associations (REAs). REAs originated during the late 1940s and 1950s. They began as farmer owned co-operatives created in order to electrify the farms of Alberta. The REAs still provide service to mainly rural Alberta. REA and distribution company systems are intertwined in the REA service area[41] and they work together to ensure there is reliable service and no duplication of distribution lines and service.

The distribution tariffs for the cities of Red Deer and Lethbridge and the towns of Cardston, Fort Macleod, Ponoka and the municipality of Crowsnest Pass are approved by their local municipal governments and town councils. The REAs have boards of directors that approve their associated distribution tariffs on behalf of their members. The cities of Calgary and Edmonton also own their electric distribution systems. The AUC regulates their distribution rates. In Alberta's remaining communities, the distribution systems are owned by either FortisAlberta Inc. (southern and west-central Alberta) or ATCO Electric Ltd. (northern and east-central Alberta). The AUC regulates the distribution rates of these two investor-owned utilities.

The following table provides the approximate length of distribution lines and number of substations associated with each distribution system owner:

[41] In Alberta, most rural areas are radial networks. A radial distribution line may serve both distribution entity and REA customers and different parts of the same line may be owned by one or the other party.

**Table 3: Alberta distribution system lines, substations and owners (lines in kilometres)**

| Type | Owner | Distribution Lines (km) | Distribution Substations (No.) |
|---|---|---|---|
| **Cities** | *Red Deer and Lethbridge* | 3,730 | 30 |
| **Municipal** | *AMPS* | 381 | 2 |
| **Rural** | *REAs** | 15,925 | 200 |
| | *CAREA/SAREA* | 6,779 | 55 |
| **AUC Regulated Utilities** | *ATCO ELECTRIC* | 69,200 | 252 |
| | *ENMAX* | 7,523 | 2 |
| | *EPCOR* | 5,288 | 10 |
| | *FortisAlberta* | 106,300 | **168 |
| **Other** | *SUNCOR* | 300 | - |

Source: Participants' written responses to Commission Questions 13 and 14, Appendix A, Exhibit 3.01.
Note: * As reported by the Alberta Federation of Rural Electrification Associations (AFREA).
** FortisAlberta does not own any substations. The 168 substations in its service area are owned by other distribution entities.

Distribution system owners are responsible for conducting load settlement calculations within their service area.[42] This responsibility is referred to as being a load settlement agent. The province is segmented into ten zones for the purpose of performing load settlement calculations. The four largest distribution system owners (ATCO Electric, ENMAX, EPCOR and FortisAlberta) act as their own load settlement agent. In the remaining six settlement zones, the distribution system owners have authorized one of the four large distribution system owners or entity third party to act as their load settlement agent. In total, there are six load settlement agents performing load settlement calculations in Alberta.

### *Micro-grids*

A micro-grid is a local energy network in which the electricity generated by multiple distributed energy resources is transmitted using a non-utility owned electrical distribution system to a multiple load center site located within the energy network. An example of a multiple load center site would be a university campus,[43] industrial park or hospital. The micro-grid's distributed energy resources could include high-frequency alternating current power equipment such as microturbines as well as direct current systems such as solar and fuel cells.

[42] See Appendix 7 – Smart metering technologies and related matters for information on load settlement.
[43] The University of Alberta operates a micro-grid on their campus.

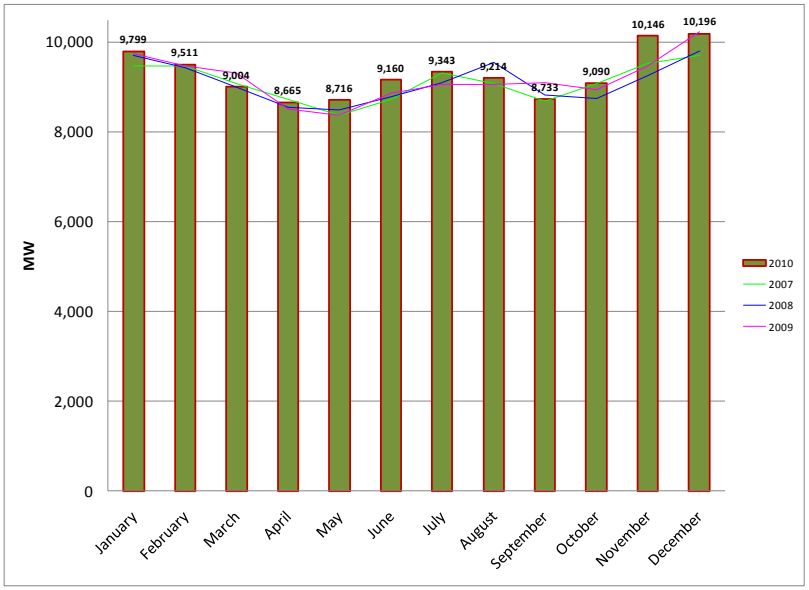
## Description of electrical load in Alberta

### *Load characteristics*

Alberta's internal load is calculated as the sum of all electricity sales (residential, commercial, industrial and farm), losses (both transmission and distribution) and industrial load from on-site generation prior to sales to the power pool (on-site load). In the past five years (2006 – 2010) Alberta hourly peak demand for the year has grown by 485 MW from 9,661 MW to 10,146 MW[44] (an overall increase of approximately 5.0 per cent).

Alberta is a double peaking system, with demand cresting in both the winter with heating and seasonal lighting demand and in the summer. However, the summer peak is lower than the winter peak due to the lack of significant air conditioning load. The figure below compares the hourly peak demand by month over the past three years:

**Figure 5: Average peak demand by month (2007-2010)**



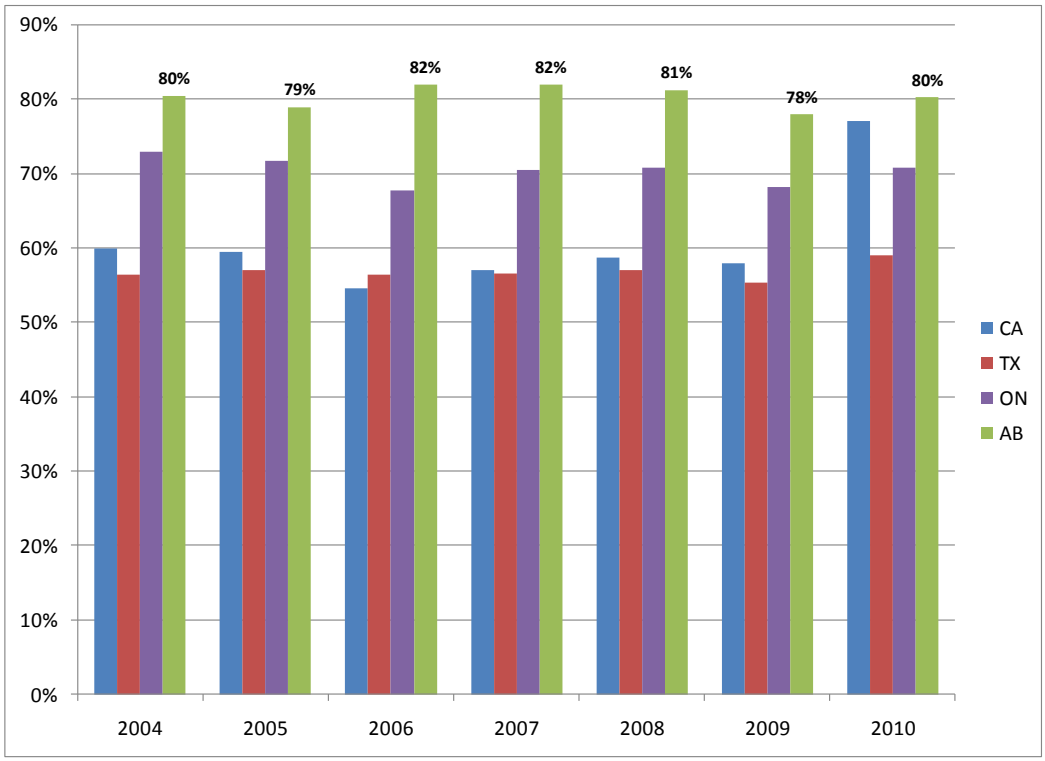

Source: AESO, Alberta Internal Load, Current Supply Demand Report.

Annual electrical energy consumption in Alberta has grown from 69,364 gigawatt hours (GWh) to 71,690 GWh during the past five years (2006-2010).[45] The high percentage of industrial load in Alberta results in a relatively flat load shape as compared to other jurisdictions such as Ontario. This is because industrial loads do not follow the same peaking tendencies as residential loads. In addition, cogeneration is a growing component of total electricity supply in Alberta as it is utilized in industrial processes to produce steam as well as for electricity generation. The

44 The Alberta Electric System Operator, "Alberta Actual Internal Supply," retrieve through NRGstream.
45 The Alberta Electric System Operator, "Alberta Actual Internal Supply," retrieve through NRGstream.

following chart illustrates the peak demand as a percentage of average demand in Alberta (AB), California (CA), Texas (TX) and Ontario (ON):

**Figure 6: Average demand as a percentage of peak demand (2004-2010)**

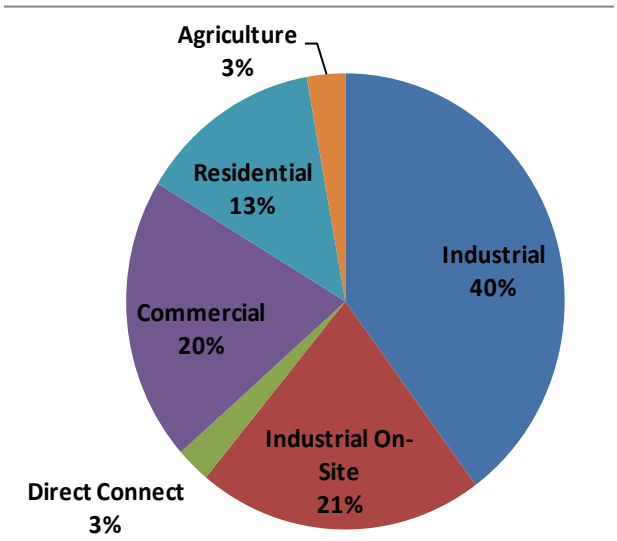



Source: (Alberta) AESO, Alberta Internal Load, Supply, Demand and Reserve Summaries webportal; (Ontario) IESO, Market Demand, Market at a Glance webportal; (Texas) ERCOT, Actual System Demand, Real-time Market webportal; (California) CAISO, Actual Hourly Demand, OASIS webportal.

Note: 2010 data are from January 1, 2010 to June 2010, whereas the other dates consist of yearly data. This does not change the conclusion, but explains the deviation from the trend in 2010.

The figure below breaks down Alberta's electrical energy usage by industrial, commercial, residential and farm sectors. As can be seen from the figure below, the majority of electrical energy consumed in the province is by large industrial loads:

**Figure 7: Customer sector as a percentage of total electrical energy usage (2009)**

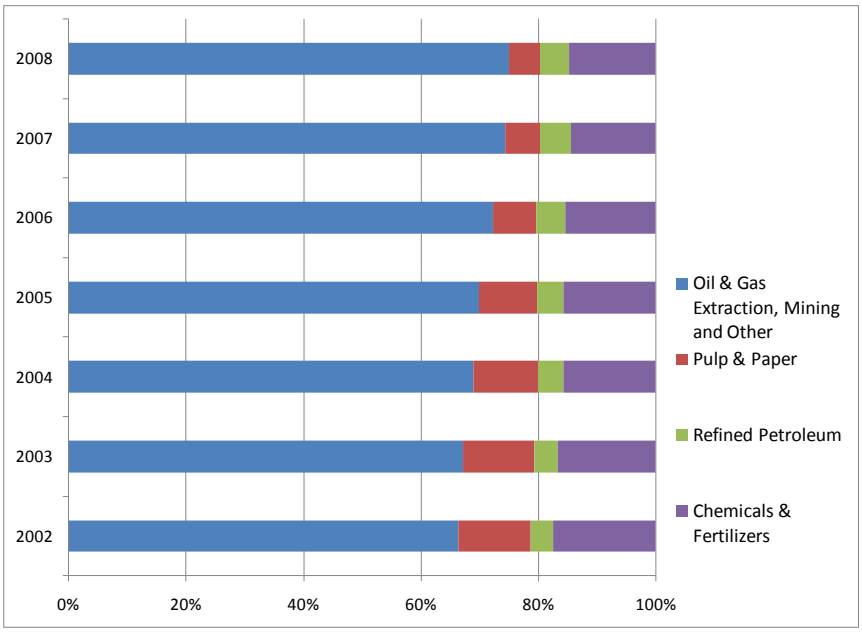



Source: ERCB, ST98-2010, "Alberta's Energy Reserves and Supply/Demand Outlook", Figure 9.4, "Alberta Electricity Consumption by Sector."[46]

Figure 8 identifies electrical energy consumption by industry sector for the years 2002 to 2008. The oil sands sector, which is comprised of sites using mining and in situ extraction techniques to remove bitumen from the ground, as well as facilities that upgrade crude bitumen into synthetic crude oil, has displayed the largest growth in total electrical energy consumption in that period of time.

[46] ERCB ST98-2010, "Alberta's Energy Reserves 2009 and Supply/Demand Outlook 2010-2019" (2010), online: The Energy Resources Conservation Board http://www.ercb.ca/docs/products/STs/st98_current.pdf .

**Figure 8: Industry electric energy demand as percentage of total industrial demand for the period 2002 to 2008**




Source: Cansim, "Supply and Demand of Primary and Secondary Energy in Natural Units, Annual: Alberta." 2009 is most recent data.

Note: "Other" includes cement, forestry, iron and steel, smelting and refining, and other industries.

# Appendix 3 – Current status of the smart grid development in Alberta

## Appendix 3 – Current status of smart grid development in Alberta

***This appendix describes the smart grid technologies that are being employed by various participants in this Inquiry at the transmission and distribution levels of the electrical system.***

Various participants in the Inquiry provided information regarding the smart grid-related activities and investments that they have undertaken to date or are planning to do. The participants agreed that the definition and the elements of a smart grid are evolving and that there is a lack of consensus as to how to define the concept. As such, the variety of reported smart grid investments and activities are equally as diverse. As acknowledged by several of the participants, many of the technologies now being touted as smart grid have been in use and deployed long before the term "smart grid" became common. Some of these smart grid technologies are briefly explained in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

### Alberta Electric System Operator and Transmission Facility Owner deployment of smart grid technologies

The Commission asked the AESO and the transmission facility owners to provide specific information regarding their smart grid activities and investments.[1] The following are examples of how smart grid technologies are being deployed, tested or evaluated to enhance the efficiency and reliability of the AIES.

#### *Alberta Electric System Operator (AESO)*

The AESO indicated it is using intelligent technologies to enhance the efficiency and reliability of the transmission system.[2] The AESO is also advancing the deployment of Phasor Measurement Units (PMU),[3] applying Dynamic Thermal Line Ratings (DTLR) technology, and applying Flexible AC Transmission Systems (FACTS) on transmission projects.[4] These technologies are described in Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels.

The AESO has proposed or introduced new rules, techniques and technologies to integrate large amounts of wind generation into the Alberta Interconnected Electric System.[5] These include proposed ISO rules for wind power generating facilities including technical requirements respecting power and ramp rate limiting, over frequency control, wind power forecasting and

[1] Exhibit 3.01, Appendix A - Questions for Smart Grid Inquiry, Question 5.
[2] Exhibit 103.01, AESO Response to Commission Question 5.
[3] Note: 27 PMUs are currently installed in Alberta.
[4] Exhibit 103.01, AESO Response to Commission Question 1.
[5] Exhibit 103.01, AESO Response to Commission Question 20.

synchrophasor measurements.[6] The AESO is also considering other refinements to the market including the development of new ramping services and the use of more operating reserves.[7]

The AESO is implementing some smart grid technologies, in particular, operator decision support tools and short-term wind forecasting, which will assist in facilitating the large-scale integration of wind generation. Decision support includes a complex arrangement of systems, tools and procedures that are used by system operators to ensure that the electric system and wholesale markets are operated reliably and in a fair and consistent manner. These mechanisms must be modified and supplemented to provide the operator with displays and tools that incorporate wind power forecasts and wind power management in day-to-day operations. The AESO is currently implementing operator decision support tools which will incorporate wind power forecasts, calculate the current ramp rate capability of the system and allocate power and ramp rate limits to wind plants if necessary.[8]

The AESO is also implementing short-term wind power forecasting tools to ensure the continued reliable operation of the grid and the fair, efficient and openly competitive operation of the electricity market.[9] Accurate wind power forecasts can help the system controller maintain the critical balance of supply and demand of electricity by indicating the timing and amount of other measures required to offset the inherent variability of wind power. A wind power forecast can also provide valuable information to market participants who can provide the necessary resources (operating reserves) to offset the variability in the wind generation output. Longer term forecasts can also provide information to market participants regarding potential periods of excess generation which may be used to plan generator maintenance.

In January 2010, the AESO contracted with a third party forecaster to provide a centralized wind power forecast for Alberta.[10] Centralized wind power forecasts will be based on site-specific meteorological data and production data provided by the wind farms.

### *AltaLink Management Ltd. (AltaLink)*[11]

AltaLink, working with the AESO, installed a DTLR system on its transmission line between the Peigan and Pincher Creek substations.[12] DTLR is a technology that can assist in the

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6 ISO Rule Section 502.1 – Wind Aggregated Generating Facilities Technical Requirements, online: AESO, http://www.aeso.ca/downloads/2010-08-10_Wind_Technical_Rule_FINAL_CLEAN.pdf.

7 K. Gunsch (prepared by K. Aksomitis), "Phase Two Wind Integration Study" (December 16, 2010), online: The Alberta Electric System Operator http://www.aeso.ca/downloads/Wind_Integration_Discussion_Paper_-_Phase_Two.pdf.

8 The Alberta Electric System Operator, "AESO Recommendation Paper - Implementation of Market & Operational Framework For Wind Integration in Alberta"( March 2009), page 44, online: AESO, http://www.aeso.ca/downloads/WI_Paper-_Final.pdf

9 The Alberta Electric System Operator, "Wind Power Forecasting Services", online: AESO, http://www.aeso.ca/gridoperations/18286.html.

10 The Alberta Electric System Operator, "Wind Power Forecasting Services", online: AESO, http://www.aeso.ca/gridoperations/18286.html.

11 Exhibit 99.02, AltaLink Response to Commission Question 5.

12 This area of the grid includes a large amount of wind generation and the transmission lines can become congested under certain operating conditions.

determination of the capability of a section of transmission line to transmit an electrical current by measuring relevant transmission line parameters and monitoring weather conditions in real-time. A potential benefit of a DTLR system is the ability to operate transmission lines closer to their thermal design capabilities, thus allowing for more efficient operation of the transmission system and improve the utilization rates of the generating resources.

The purpose of this pilot project was to assess the ability of the technology to provide a safe and reliable increase to the thermal line rating, to gain operating experience with the technology, to determine the achievable and sustainable benefits, and to identify integration issues with the existing AltaLink system and processes.

AltaLink discovered a number of issues when deploying and operating the technology. For example, a number of modifications to business processes were required during the pilot project to integrate the DTLR system into AltaLink's control centre as well as that of the AESO's. A recalibration of the DTLR system was required every time there was a physical modification made to the transmission line in order to ensure the accuracy of the monitoring devices. AltaLink's experience confirmed the need for additional research before pursuing any further DTLR pilot projects or the large-scale deployment of the technology.

AltaLink has also installed PMUs at a number of its substations. These devices have the capability of measuring and reporting on the operating condition of the transmission system at an extremely fast rate (up to 30 times per second). Historical PMU data is being used by AltaLink for analyzing system outages. Future application of this technology would include the use of PMU data to monitor the performance of the transmission system in real-time.

AltaLink installed monitoring instruments on its critical transformer units. These instruments provide an alert to AltaLink's operating centre personnel of developing fault conditions that could lead to equipment failure or unplanned outages.

All new AltaLink substations have a substation Local Area Network (LAN) installed. Several existing substations have been retrofitted with a LAN through AltaLink's on-going program to have a LAN at all substations with high-speed telecommunications. LAN security at the substation level include physically separate communications networks that connect the substation's protection, control, automation, and monitoring systems and devices with the Supervisory Control and Data Acquisition (SCADA) systems. This level of network security reduces the chances of unwanted electronic intrusion (accidental connection by authorized users and unwanted connections by unauthorized users), thereby protecting the integrity of the data and information created and exchanged by the substation devices.

AltaLink also upgraded its wide area communications systems with the installation of optical ground wire on its high-voltage transmission towers as well as the use of digital radios in its microwave network. Another upgrade to the communication system will be the deployment of the Multiprotocol Label Switching (MPLS) system. The reported advantages of an MPLS system are its scalability, its ability to be used in various communications network protocols and its capability to prioritize and route various forms of data (video, data, and voice) using the most efficient means across the communications network.

### *ATCO Electric Ltd. (ATCO)*[13]

ATCO recently implemented an upgrade to its energy management system which is used to continuously monitor and control the performance of its transmission system and to exchange status and operating information with the AESO. ATCO also indicated that it has employed line autoreclosing schemes and sectionalizing schemes to isolate faults and restore service. ATCO has employed remedial action schemes which help to maintain system stability following a disturbance. Static VAR Compensators (SVC) and synchronous condensers have also been employed to provide voltage control to maintain system stability. ATCO also implemented a private telecommunications network to make their SCADA system a more reliable and secure network.

### *The Cities of Lethbridge and Red Deer*[14]

Beginning in 2002, the City of Lethbridge upgraded the protective relays[15] on its 138-kV transmission lines. The upgrade replaced electromechanical devices with standardized, digital protective relays. The City of Lethbridge expects to start the next cycle of replacement in the 2017 to 2022 time frame. The City of Lethbridge stated that the upgrade was motivated by best utility practices.

The City of Red Deer is in the process of replacing the protection and control system at one of its substations. The City of Red Deer cited the program as an example of a best utility practice as the existing system for protection and control was nearing the end of its service life and more advanced technology was economically available to replace the obsolete system.

As well, the City of Red Deer noted that the communication networks and substation automation systems (protection, control and monitoring) in this substation would conform to the information and communication standard developed by the International Electrical Committee, namely IEC 61850.[16] This standard provides the means for high-speed, device-to-device communications within the substation and promotes interoperability at the communications level within the substation. Both the Cities of Lethbridge and Red Deer have taken steps to make their SCADA[17] communications network a dedicated one to enable the continuous and uninterrupted flow of data from the remote equipment to the operations center.

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13 Exhibit 91.01, ATCO Response to Commission Question 5.

14 Exhibit 69.01, The Cities of Lethbridge and Red Deer Response to Commission Question 5.

15 Protective relays monitor electric power measurements (current, voltage, and frequency) on transmission lines and trigger a circuit breaker to open when a fault or abnormal condition, which could threaten the integrity and reliability of the transmission line is detected.

16 IEC 61850 is the internationally accepted and used standard for information, information exchange and system device configuration in electric power systems. It enables intelligent electronic devices (IEDs) from one or different manufacturers to exchange control, protection and monitoring information with one another.

17 SCADA systems in the electric industry remotely monitor and control transmission and substation devices using computer systems at geographically dispersed sites.

### *EPCOR Distribution & Transmission Inc. (EDTI)*[18]

EDTI noted that very few activities and investments were undertaken on its transmission system, solely because they were considered to be smart grid technologies. EDTI stated that they installed substation automation systems to better control, protect and monitor its substation equipment as a matter of good business practice. The installation of substation automation communication systems also permitted intelligent electronic devices, which perform electrical protection, control and monitoring functions, to exchange information with one another and enable the individual intelligent electronic devices to use that information to perform its designed function.

### *ENMAX Power Corporation (ENMAX)*[19]

ENMAX stated it had not undertaken activities and investments on its transmission system for the sole purpose of developing a smart grid system. ENMAX indicated that investments in power system management technologies, such as substation pollution monitoring, data acquisition, condition monitoring and communications are considered when the application of good business and engineering practices can financially support the need for the investment.

## Distribution System Owners

The Commission invited distribution system owners to provide specific information regarding their smart grid activities and investments.[20] The participants, which included rural electrification associations, municipally-owned utilities, ATCO Electric Ltd., EPCOR Distribution and Transmission Inc., ENMAX Power Corporation and FortisAlberta Inc., provided the following examples of how smart distribution technologies were being deployed, tested or evaluated in their respective distribution systems.

In general, participants indicated that smart distribution technologies contributed towards greater awareness, control, and automation of the operations of a distribution system. The expected benefits of an automated distribution system include greater system reliability (a reduction in the number and duration of outages), more efficient operations (better control of voltage and frequency regulations, reduced line losses) and enhanced asset management (improved equipment protection, better load forecasting capabilities).

### *Alberta Federation of Rural Electrification Associations (AFREA)*[21]

The AFREA identified a number of smart grid technologies and investments that its member REAs have undertaken. AFREA noted the implementation of Automatic Meter Reading (AMR) systems in 90 per cent of the member Rural Electrification Associations (REA). Some of the

[18] Exhibit 108.02, EDTI Response to Commission Question 5.
[19] Exhibit 102.03, ENMAX Response to Commission Question 5.
[20] Exhibit 3.01, Appendix A – Questions for Smart Grid Inquiry, Question 12.
[21] Exhibit 117.01, AFREA Response to Commission Question 12.

REAs are using radio frequency technology to have their meters read by using an airplane to collect the readings. AFREA indicated that meter reading costs decreased by 94 per cent due to the substantial reduction in time required to read the meters while meter reading accuracy remained high at 99 per cent. The AFREA also noted that their AMR systems are able to detect and report on meter tampering activities.

The AFREA also cited the implementation of energy efficiency audits for individual members and is working towards implementing a rural pilot project which would supply in-house display devices for the purpose of monitoring household usage. At the utility level, system planning, physical distribution system and yard audits of REA distribution systems are being carried out on a regular basis to identify the need for upgrading the equipment.

### *Alberta Municipal Power Systems (AMPS)*[22]

The membership of the Alberta Municipal Power Systems group includes the Towns of Cardston, Fort Macleod and Ponoka, and the Municipality of Crowsnest Pass. Only the Town of Ponoka identified investments in technologies that could be considered smart grid; that being the installation of 1,125 residential digital meters, 94 digital demand meters and one time-of-use digital meter. All meters in Ponoka continue to be manually read.

### *ATCO Electric Ltd. (ATCO)*[23]

ATCO stated that it continuously undertakes system enhancements to maximize the operational and cost-effectiveness of its distribution system. ATCO indicated that it has undertaken the following activities and investments that are considered smart grid technologies: an AMR system, distribution automation schemes in select locations, an outage management system, a work force management system, a geographic information system and the development of distribution automation/distribution SCADA standards.

### *South Alta Rural Electrification Association Limited (SAREA)*[24]

SAREA has implemented digital AMR meters throughout its service area. At the Inquiry,[25] SAREA noted that it chose digital meters because they were the only suitable technology available and the most cost- effective to purchase.

### *Cities of Red Deer and Lethbridge*[26]

The City of Lethbridge is undertaking a multi-year capital program to replace older distribution switching cubicles with remote SCADA operable switches. The City of Lethbridge also indicated that it had installed 14,000 AMR meters and that both upgrade programs were motivated by best utility practice.

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22 Exhibit 96.02, AMPS Response to Commission Question 12.
23 Exhibit 91.01, ATCO Response to Commission Question 12.
24 Exhibit 82.02, CAREA and SAREA Response to Commission Question 12.
25 Transcript, Volume 3, page 723.
26 Exhibit 69.01, Cities of Red Deer and Lethbridge Response to Commission Question 12.

The City of Red Deer installed a SCADA system for all of its nineteen electrical vaults in its downtown area to allow for remote monitoring and stated that the investment was motivated by best utility practice. It has plans to convert the 4-kV system in the downtown area to 25-kV. Under a multi-year project, the City of Red Deer will upgrade its communication system and its control and protection devices to intelligent electronic devices to further automate its system.

***EPCOR Distribution &Transmission Inc. (EDTI)***[27]

EDTI stated it has undertaken the following activities and investments that are considered smart distribution technologies: replacement of its geographic information system and further deployment of distribution automation systems.

EDTI noted that its geographic information system captures, stores and presents information regarding the location of every grid component (transformers, switches, poles, cables) and the electrical connection between each grid component. EDTI cited the use of distribution automation systems to isolate outages more rapidly, thereby restoring service to most customers and allowing work crews to focus their efforts on the outage source. EDTI installed its first distribution automation system in 2007-2008. EDTI stated that in 2010 it deployed distribution automation systems to four 25-kV circuits and in 2011 intends to deploy additional distribution automation systems to improve the reliability on six 25-kV feeders.

***ENMAX Power Corporation (ENMAX)***[28]

Distribution system initiatives implemented by ENMAX in recent years include an auto-restoration (self-healing) distribution automation system deployed on 17 per cent of its existing three-phase switches, a distribution strategic technology application roadmap (which includes the integration of a graphical information system and an outage management system), and a comprehensive SCADA communication system for its distribution system.

***FortisAlberta Inc. (FortisAlberta)***[29]

FortisAlberta is installing smart meters and an advanced metering infrastructure system throughout its service area to enable it to perform automated meter reads. The deployment is expected to be completed by the end of March 2011. Distribution automation systems are being deployed in targeted areas of its service area to improve system reliability. FortisAlberta has also invested in geographic information systems that provide a detailed and accurate mapping of its electrical distribution system including the interval metering devices for large commercial and industrial customers.

[27] Exhibit 108.02, EDTI Response to Commission Question 12.
[28] Exhibit 102.03, ENMAX Response to Commission Question 12.
[29] Exhibit 100.02, FortisAlberta Response to Commission Question 12.

# Appendix 4 – Status of smart grid deployment in other jurisdictions

## Appendix 4 – Status of smart grid deployment in other jurisdictions

***In the Order-in-Council, the AUC is instructed to gather information with respect to smart grid deployment in other jurisdictions. The following is a sampling of smart grid initiatives in other jurisdictions.***

### Introduction

Governments and businesses in the energy sector the world over are increasingly considering the use of smart grid technologies to address concerns regarding the environmental impacts of fossil-fuelled sources of generation, sustaining economic growth, integrating renewable energy sources, promoting economic efficiency and enhancing system stability and reliability through automation. Electricity grids were originally built to handle the bulk transmission of generation produced by a small number of large centralized plants. Electricity was designed to flow through transmission lines in one direction. Independent System Operators used supply side resources such as responsive gas plants or hydroelectric facilities to balance the supply and demand for electricity. Digital smart grid technologies that monitor and match supply and demand at the generation plant and consumer end respectively, would be required to support advanced power transmission and distribution infrastructures that are capable of bi-directional flows and incorporating renewable and distributed generation in a streamlined and non-disruptive manner.

The Electric Power Research Institute estimated the cost of constructing a smart grid network in the United States to be $165 billion over the next twenty years. A report released by Pike Research on December 28, 2009 predicted global spending in smart grid technologies will amount to $200 billion between the years 2008 and 2015.[1]

However, a survey by Microsoft Corp. revealed that only eight per cent of utilities around the world have completed their smart grid technology implementations while 37 per cent have projects underway and more than half have not yet started.[2]

This section reports on the status of smart grid initiatives in a number other jurisdictions. This section also observes that jurisdictions that had not initially adopted smart grid initiatives are now examining the experiences in other jurisdictions and their own circumstances in order to ensure that there will be benefits for customers. Many jurisdictions are conducting inquiries and carrying out trials for the purpose of determining whether a wider adoption is justified.

[1] Pike Research, News Release, "Smart Grid Investment to Total $200 Billion Worldwide by 2015" (December 28, 2009), online: Pike Research Newsroom http://www.pikeresearch.com/newsroom/smart-grid-investment-to-total-200-billion-worldwide-by-2015.

[2] Microsoft Press Release, "Smart Grid Revolution Becomes "Disruptive" for Utilities Worldwide According to New Microsoft Survey" (March 11, 2010), online: Microsoft News Center, http://www.microsoft.com/presspass/press/2010/mar10/03-11SmartGridPR.mspx.

## Canada

The British Columbia government issued a ministerial order and regulation in December 2010 that prescribed the functional requirements for smart meters, the timing for the installation of the smart meters as well as the requirements and timing for the deployment of a telecommunications network for the distribution system. Specifically, smart meters were to be installed by the end of 2012, while the telecommunications network was to be fully functional by the end of calendar 2015. Subsequently, BC Hydro announced plans to install 1.8 million smart meters throughout its service area, as well as to upgrade the telecommunications and information systems along its network, all at a cost of $930 million. BC Hydro stated that almost 80 per cent of the quantified benefits expected from its smart metering program will be derived from operational efficiencies within BC Hydro.[3] The existing rate structures will be maintained for customers, however, BC Hydro intends to provide voluntary time-of-use rates to those who are interested in the program.

Manitoba Hydro completed a pilot project in 2009 involving 5,000 electricity customers in Winnipeg and 200 customers in rural locations to assess the potential for advanced metering technology to improve system reliability, increase accuracy in billing and assist in energy conservation efforts. The assessment of the pilot project concluded that further confirmation of the future benefits and a more detailed analysis of the project risks was required before a supporting business case could be completed.[4]

In New Brunswick, NB Power will be deploying communications technologies that could support the integration of wind generation by controlling commercial and residential loads through fast responding demand response programs. Specifically, NB Power will be installing communication devices to equipment and appliances in customers' homes and businesses that will allow for non – intrusive control of electricity consumption to match the variable supply provided by wind generation.[5]

The provinces of New Brunswick, Nova Scotia and Prince Edward Island, with funding from the federal government, announced plans to undertake a joint demonstration project to assess the abilities of smart grid technologies to manage the delivery of renewable electricity across communities in the three provinces. The focus is on the integration of smart grid technologies, residential customer demand response programs and variable renewable electric energy

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[3] BC Hydro, "Smart Metering & Infrastructure Program Business Case" (January 2011), online: BC Hydro, http://www.bchydro.com/etc/medialib/internet/documents/smi/smi_business_case.Par.0001.File.smi_business_case.pdf.

[4] Manitoba Hydro, "2010/11 & 2011/12 General Rate Application Filing, Appendix 24 AMI Status Report" (February 2, 2010) online: Manitoba Hydro, http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_24.pdf.

[5] NB Power, News Release, "NB Power continues to seek innovation for customers through the Maritime Provinces Customer Load Control for Wind Integration Project" (March 23, 2010), online: NB Power Press Releases, http://www.nbpower.com/html/en/about/media/media_release/pdfs/Final%20English%20Press%20Release%20-%20March%2023,%202010.pdf.

production to balance the electricity system that relies on renewable energy sources for its electricity.[6]

The Ontario experience with smart grid and smart metering technology will be discussed later in this section.

## United States of America (federal level)

The *Energy Policy Act of 2005* intended to promote the diversification of U.S. energy sources and the development of alternative sources of energy by providing tax incentives and loan guarantees for energy production of various types (e.g. biofuels, wind, wave and tidal power, geothermal), encourage conservation and efficiency in energy use, and increase the domestic production of oil and natural gas.[7] The *Energy Policy Act of 2005* set out a requirement for establishing mandatory reliability standards and required state regulators to consider the implementation and adoption of smart metering standards and time-based pricing, as well as to identify and develop demand response programs, all of which was predicated upon the deployment of smart grid technologies.

*The Energy Independence and Security Act of 2007* made smart grid a federal policy and set out the goals for modernizing the electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure through the use of smart grid technologies. It also provided funding for smart grid research and development and established a matching program to help fund smart grid investments. It also directed state regulators to encourage utilities to employ smart grid alternatives before approving investments in traditional technologies.

*The American Recovery and Reinvestment Act of 2009* established funding opportunities for smart grid investments through the Smart Grid Investment Grant (SGIG) Program and allocated $11 billion in funding to promote deployment of smart grid technologies to modernize the electric grid. *The American Recovery and Reinvestment Act of 2009* funding was intended to reduce unemployment and stimulate the economy.[8] Applicants were eligible for smart grid matching funds of up to 50 per cent of the qualifying investments. One hundred companies, utilities, manufacturers, and others were awarded $3.4 billion in matching grants to stimulate smart grid investment. These grants are being matched by industry funding; bringing the total investment in smart grid technologies to $8 billion.[9]

This funding mechanism ensures that 50 per cent (or less) of the cost of eligible grid investments falls to ratepayers or shareholders. *The American Recovery and Reinvestment Act of 2009* gave

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[6] Natural Resources Canada, News Release, 2010/58, "The Government of Canada Invests in Clean Energy in Atlantic Canada," (July 23, 2010) online: Natural Resources Canada Media Room, http://www.nrcan-rncan.gc.ca/media/newcom/2010/201058-eng.php.

[7] *Energy Policy Act of 2005*, (2005), US Congress - Public Law 109–58, (August 8, 2005), online: http://www.epa.gov/oust/fedlaws/publ_109-058.pdf.

[8] *American Recovery and Reinvestment Act of 2009*, (2009), online: Recovery Gov, http://www.recovery.gov/About/Pages/The_Act.aspx.

[9] U.S. Department of Energy, Press Release, "President Obama Announces $3.4 Billion Investment to Spur Transition to Smart Energy Grid" (October 27, 2009), online: Energy Gov, http://www.energy.gov/8216.htm.

preference to projects that could be started and completed quickly. Entities awarded federal funding grants still required the approval of their respective state commissions, who have the jurisdiction regarding the cost recovery for capital investments, which would include any SGIG project.

There are ten states[10] in the United States that collectively were awarded 42 per cent, or $1.9 billion, of the federal funding available under *The American Recovery and Reinvestment Act of 2009* for smart grid investments. These states are deploying smart grid technologies for a number of reasons. Foremost is the states' effort to comply with the requirement of the *Energy Independence and Security Act of 2007*. The *Energy Independence and Security Act of 2007* made smart grid investment a federal policy and set out the goals for modernizing the electricity transmission and distribution system through the use of smart grid technologies.

Recent decisions at the state level, however, where smart grid initiatives were not mandated by legislation, have not looked favorably on smart grid projects, specifically with respect to cost recovery from ratepayers, despite the availability of federal funding. Four examples illustrate this.

On June 21 2010, the Maryland Public Service Commission (PSC) rejected Baltimore Gas and Electric Co's (BGE's) original $835 million smart grid proposal. The PSC indicated the business case to be untenable despite the availability of $136 million in SGIG funding for the project. On August 16, 2010, the PSC approved BGE's revised smart grid proposal on the condition that the project's costs be recovered through the traditional ratemaking process rather than using the surcharge method requested by BGE. The result of the approval is that BGE will be required to pay for the project first, then demonstrate quantifiable benefits to customers before being able to request for the recovery of its prudently incurred costs. The PSC also established metrics to track the progress of the smart grid project and the benefits to customers.

On June 30, 2010, the Public Utilities Commission of Ohio approved a $72 million smart grid pilot program for FirstEnergy Corp, which received a $36 million in SGIG funding for the project. However, the regulator stated it would address the issue of cost recovery associated with the program at a later date. Consequently, the utility announced it would not proceed with the project.

On July 1, 2010, Oklahoma Gas and Electric Co received approval to spend up to $366 million over the next three years to deploy smart meters across its Oklahoma service territory and install smart grid equipment on its distribution system, with SGIG funding contributing approximately $130 million towards the project. The utility however was required to guarantee operational and maintenance cost reductions that were expected to accumulate to $22.5 million by 2013 and pass these reductions to consumers through credits on their bills.

On September 30, 2010, the Illinois Appellate Court reversed an Illinois Commerce Commission (ICC) decision that would have allowed Commonwealth Edison (ComEd) to impose a line item

[10] California, Colorado, Florida, Massachusetts, New Jersey, New York, North Carolina, Ohio, Pennsylvania and Texas.

charge on consumers' monthly electricity bills to pay for an advanced metering infrastructure (AMI) pilot project. The court ruled the ICC violated state laws in conducting a single-issue ratemaking proceeding to establish the cost-recovery mechanism that allowed ComEd to collect its projected AMI costs before having to demonstrate the benefits to customers. In response to the court decision, ComEd indicated its pilot project, which was to cost $69 million and lead to the installation of 130,000 smart meters by May 2011 could be terminated early if an alternative cost recovery mechanism cannot be established.

Other reasons for implementing smart grid technologies were to comply with state-mandated renewable portfolio standards and energy conservation objectives (California, Colorado, Massachusetts, North Carolina and Pennsylvania), to stimulate the state economy and create jobs (New Jersey and Ohio) to produce a net benefit for the companies and the consumers (Florida, New York and Texas). Despite the availability of the federal funding, a number of these states are taking a measured and deliberate approach to deploying and implementing smart grid technologies. For instance, New York and Colorado have launched inquiries to determine the regulatory policies that should be in place to guide the pace of smart grid technology development. Massachusetts, New Jersey, North Carolina, Ohio and Pennsylvania are using pilot projects to test the applicability of the technologies in meeting the state's energy goals and delivering the expected benefits to the companies and customers.

States that have no specified energy policies or regulations (i.e., energy efficiency, renewable energy) appear to be taking the approach of learning from the experiences of the more active states. For example, lawmakers in Arkansas, Idaho, Illinois, Iowa, Kentucky, Montana and Virginia created committees or directed their public utilities commission to study, review and evaluate smart grid technologies, deployment activities of other states and report on the suitability of implementing the technologies. A few, such as North Dakota, Utah and West Virginia have no state policy or utility activity associated with smart grid deployment at this time.

## Federal Energy Regulatory Commission (FERC)

The FERC introduced a number of measures to advance the development of a smart electric transmission system. On July 16, 2009 the FERC issued its Smart Grid Policy Statement that set out the priorities to guide the industry in developing the key smart grid standards for achieving interoperability and functionality of smart grid systems and devices.[11] The policy statement was issued to comply with the requirements of *The Energy Independence and Security Act of 2007*, which directed the FERC to institute a rulemaking proceeding to adopt the necessary standards and protocols to achieve the smart grid capabilities and expectations set out in *The Energy Independence and Security Act of 2007*. The FERC intends to establish these standards and protocols by adopting, as appropriate, the standards and protocols developed through the collaborative process coordinated by the National Institute of Standards and Technology (NIST). *The Energy Independence and Security Act of 2007* directed the NIST to coordinate the development of smart grid standards.

[11] Federal Energy Regulatory Commission, *Smart Grid Policy*, 128 FERC 61,060 (July 16, 2009) ,online: FERC http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-3.pdf.

The smart grid policy statement also set out the FERC's policy for recovery of costs by utilities that are early adopters of smart grid technologies. Specifically, the statement addressed the manner by which the costs associated with smart grid investments, as well as the recovery of the stranded costs of legacy systems that are to be replaced by smart grid will be reviewed for rate treatment purposes. The stated intent of the proposed rate treatment is to encourage the adoption of and investment in smart grid technologies, especially for investments that demonstrate system security and compliance with FERC-approved reliability standards, among other requirements.

The FERC and the National Association of Regulatory Utility Commissioners (NARUC) formed the Smart Grid Collaborative as a means for discussing and understanding the issues related to pursuing and deploying grid modernization technologies. NARUC is an organization representing the State public service commissions who regulate utilities providing services such as energy, telecommunications, water and transportation. The FERC and NARUC recognized the benefits of combining their efforts, while respecting each other's jurisdiction, to facilitate the transition to a smart electricity grid.

### United States of America and Canada (state and provincial level)

Various states and public utility commissions are considering the merits of deploying smart grid technology to achieve state and federal policies promoting energy efficiency and conservation, reducing greenhouse gas emissions, achieving renewable portfolio standards, introducing new technologies, and regulating electricity production from fossil fuels. The states which are considered to be the most advanced with respect to policy development, planning, implementation and deployment of smart grid include Colorado, Massachusetts, California and Texas. The implementation and deployment of smart grid in Ontario is also addressed below.

A summary of the smart grid activities occurring in these more active jurisdictions is provided in the next section of this report.

## Colorado

### *Market statistics*

| 2009 Data[12] | |
|---|---|
| Net Generation by fuel type | Natural Gas 45%<br>Coal 38%<br>Wind 8%<br>Water 8%<br>Other 1% |
| Installed capacity (MW) | 14,083 |
| Net Generation (MWh) | 50,910,668 |
| Customer Electricity Sales Mix | Commercial 40%<br>Residential 34%<br>Industrial 26% |

[12] US State Data Source: SNL Financial LC. Used with permission.

| | |
|---|---|
| Population (2010) | 5,114,102 |
| Utility Supply Pricing Mechanism | Tiered seasonal rate structure in effect for Xcel Energy, the largest electric utility operating in Colorado. Customers pay 9.7cents/kWh for usage during the peak summer months (June to September) and 9.65 cents/kWh during the other non-peak months of the year. During the summer season, usage that exceeds 500 kWh in the month will be charged 14 cents/kWh. |

### *Legislative activity*

On March 22, 2010, House Bill 1001 (Renewable Energy) was signed into law. The bill increased the state's renewable energy standards from 20 per cent to 30 per cent by 2020. The legislation also mandated that three per cent of total electricity sales originate from distributed generation resources as a means of encouraging homeowners and small business owners to install solar power units for the purpose of generating their own source of electricity.

Colorado Senate Bill 10-180 creates an 11-member task force to gather information and report to the legislature and Colorado Public Utilities Commission on issues related to the development and implementation of a smart grid in Colorado. The task force met from July to December 2010 to deliberate issues and released its report and recommendations in late January 2011. Two overarching recommendations in the report were to conduct analyses of the benefits and implications of deploying a smart grid infrastructure on all stakeholders from a statewide perspective and to use market incentives and innovation, rather than mandate, to promote the development of a smart grid.[13]

### *Regulatory activity*

The Colorado Public Utilities Commission (Colorado PUC) issued a notice of proposed rulemaking in September 2008 to re-evaluate the rules concerning renewable energy standards. This rulemaking was initiated in light of the revised policy of the state legislature as well as to address issues with the current renewable energy standard rules.

On October 31, 2008, the Colorado PUC issued its rulemaking decision. The decision confirmed the requirements of an earlier rule which mandated utilities to procure or generate an increasing amount of its electricity supply from renewable energy resources. Specifically, investor-owned utilities are required to supply an increasing amount of electricity from renewable energy such that by the year 2020, 20 per cent of retail electricity sales is supplied by renewable energy sources.

The Colorado PUC opened an investigatory docket on February 24, 2010 to explore the general concepts of smart grid and advanced metering and to develop policies related to smart grid and

[13] Colorado Smart Grid Task Force, "Deploying Smart Grid in Colorado" (January 2011), online: Governor's Energy Office, http://rechargecolorado.com/index.php/programs_overview/smart_grid_task_force/.

advanced metering infrastructure that would encourage innovation and energy efficiency from the utilities subject to its jurisdiction.[14]

The Colorado PUC released a decision[15] outlining the preliminary results of its smart grid investigation on October 1, 2010. The Colorado PUC found smart grid has the potential to offer substantial, real and quantifiable benefits, especially smart grid components that provide utility-specific benefits such as improved operational efficiency, improved power quality and reduced outages. The Colorado PUC believed utilities should deploy smart grid components that could be readily justified by a cost-benefit analysis, and that the installation of the full suite of smart grid technologies might not be necessary.

The Colorado PUC also observed that a mass deployment of smart meters and related technologies, coupled with the introduction of time-sensitive rates might not provide the system benefit expected from smart metered enabled demand response programs. The Colorado PUC recognized the residential customer class is not homogeneous in terms of electric usage and behavioral response to more information regarding pricing and consumption. The Colorado PUC believes a more targeted approach may be required to deploy smart grid technologies to the residential customer class and intends to explore this issue in utility-specific applications.

The Colorado PUC also found that a greater reliance on intermittent renewable energy sources such as wind would pose unique operational and economic challenges for the transmission system operators. The Colorado PUC noted that smart grid technologies such as weather forecasting applications and devices that control load or generation have the potential to support the integration of more renewable energy sources and keep the electric system in balance.

Lastly, the Colorado PUC concluded that smart grid applications from the utilities should contain information addressing issues related to consumer education programs, the adverse financial impacts that demand response programs could have on the utility's ability to recover its costs and the utility's proposal to mitigate these adverse financial impacts.

The Colorado PUC invited stakeholders to provide comments on a number of topics that were not addressed in its preliminary results, including rate design changes, meter installation roll-out strategies, framework for evaluating and quantifying the societal and future benefits of smart grid investments and minimal filing requirements for applications seeking cost recovery for smart grid investments.

### *Utility activity*

In December 2007, Xcel Energy Inc. (Xcel) established a smart grid consortium with various service providers in the electricity industry for the purpose of promoting the design and deployment of a fully functioning smart grid model and chose Boulder, Colorado to be its first smart grid city.

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[14] Colorado Public Utilities Commission, "Order opening an investigatory docket", Decision No. C10-0188, (February 24, 2010).

[15] Colorado Public Utilities Commission, "Order Stating Preliminary Conclusions and Requesting Further Comments", Decision No. C10-1077 (September 29, 2010).

Xcel's intent was to demonstrate the capabilities of smart grid technologies in providing consumers with more timely and relevant information on their energy consumption patterns so that consumers would have the ability to manage their energy use more effectively. Xcel expected the smart grid technology to improve the operational efficiency and maximize the reliability of its distribution network by using real-time information to automate decision-making processes on its distribution network.

In September 2009, Xcel completed the construction of the smart grid infrastructure and related information and communication.

Advanced metering infrastructure was installed to provide real time, high-speed, two-way communication throughout the distribution grid. Three substations were fully automated with equipment capable of remotely monitoring and processing operational data and automating responses. A network-wide system of sensors to collect and report real-time information on low-voltage issues, and automatically notify Xcel personnel of outages was installed.

In-home control devices and related infrastructure to support up to 1,000 dispatchable distributed generation technologies (including plug-in hybrid electric vehicles with vehicle-to-grid technology; battery systems; wind turbines; and solar panels) were provided to customers. Approximately 200 miles of fiber optic cable, 4,600 residential and small business transformers and nearly 16,000 smart meters were connected to the smart grid system.[16]

The in-home energy management technologies gave all Boulder customers with a smart meter greater access to energy consumption information and the ability to review their in-home energy usage. In-home energy management devices allowed customers to design and personalize their energy consumption pattern by remotely and automatically controlling energy consumption for specified devices (such as air conditioners or dishwashers) based on hourly energy costs and environmental factors.

As part of the Smart Grid City project, Xcel implemented a retail pricing pilot program to the residents of Boulder City. Customers participating in the program had three pricing options. The first pricing option was a time-of-use rate where customers were charged more for electricity used at peak times of 2 to 8 p.m., with rates higher in the summer than in the winter. The second pricing option was a critical peak pricing where customers were charged a slightly lower peak-demand pricing than the time-of-use option in both seasons. However, an additional charge for electricity consumed during so-called critical peak days, estimated to occur about 15 days a year when demand on the grid is highest will also be imposed. The third pricing option was a peak time rebate where customers who reduce electricity consumption below normal levels on critical peak days would be provided a rebate.

For the remaining customers in the Xcel service area, the Colorado PUC approved a tiered seasonal rate structure that took effect on June 1, 2010. The rates were designed so that

[16] Xcel Energy, News Release, "SmartGridCity becomes first fully functioning smart grid in the world" (September 8, 2009), online: Excel Energy Newsroom, http://www.xcelenergy.com/Colorado/Company/Newsroom/Pages/NewsRelease2009-09-08-SmartGridCitybecomesfirstfullyfunctioningsmartcityintheworld.aspx.

customers would pay more for higher usage during the peak summer months (June to September) and less during the other non-peak months of the year. During the summer season, usage that exceeds 500 kWh in the month would be charged a higher tier rate.

A concern of the smart grid city project has been the construction costs. The Colorado PUC, in a decision issued on December 24, 2009 ordered Xcel to file for a certificate of public convenience and necessity (CPCN) if Xcel wanted its expenditures for the smart grid city project recovered from customers through its distribution rates. The Colorado PUC cited the cost and magnitude ($45 million) and the uniqueness of the project, including the deployment of new technologies as reasons for the CPCN. A CPCN proceeding would allow the Colorado PUC to examine whether the costs incurred are prudent and in the public interest, and to monitor these costs in the future.[17] In a related development, the city of Boulder, Colorado withdrew from the Colorado PUC hearing that was to determine whether Xcel should keep the $45 million in costs it is already recovering from customers. Initially, the city supported the recovery of all the costs, revised its testimony to support a capped amount then withdrew its participation altogether. The city cited disappointment and declining confidence that the project will deliver on the benefits promised and questioned the prudency of the smart grid investment.[18]

On October 27, 2010 an administrative law judge recommended full recovery of the smart grid city project costs from ratepayers. The Colorado PUC received objections to the judge's ruling and is now required to review the application to reverse, affirm or modify the decision.

## Massachusetts

### *Market statistics*

| 2009 Data | |
|---|---|
| Net Generation by fuel type | Natural Gas 48%<br>Oil 20%<br>Water 13%<br>Coal 12%<br>Nuclear 5%<br>Biomass 2% |
| Installed capacity (MW) | 15,106 |
| Net Generation (MWh) | 40,884,863 |
| Customer Electricity Sales Mix | Residential 36%<br>Commercial 33%<br>Industrial 31% |
| Population (2010) | 6,555,736 |

[17] Colorado Public Utilities Commission, "Order Addressing Phase I and ECA Issues", Decision No. C09-1446 (December 1, 3, and 22, 2009), page 59.

[18] Colorado Public Utilities Commission, "City of Boulder's Withdrawal of Cross-Answer Testimony and Notice of Withdrawal from Docket", Docket No. 10A-124E (August 20, 2010).

| | |
|---|---|
| Utility Supply Pricing Mechanism | Residential and small commercial and industrial customers have the option of choosing between a variable monthly or six-month fixed pricing plan. Medium and large commercial and industrial customers are charged a fixed three-month rate that is adjusted quarterly. Average retail rates are residential 15.26 cents/kWh, commercial 14.99 cents/kWh and industrial 13.34 cents/kWh. |

### *Legislative activity*

On July 2, 2008, the *Green Communities Act*, energy legislation promoting among other things, the statewide development of renewable energy and energy efficiency programs, came into effect. The *Green Communities Act* requires utility companies to obtain an increasing amount of its electricity from renewable energy sources and establishing "net-metering" programs to enable owners of micro generation to sell their excess electricity into the grid.

The *Green Communities Act* also dealt with smart grid. Section 85 of the *Green Communities Act* required each electric distribution company to file a plan with the Massachusetts Department of Public Utilities (DPU) to establish a smart grid pilot program. The intent of the smart grid pilot programs was to gain an understanding of the impact of providing customers with dynamic pricing structures (i.e., time-of-use or hourly energy pricing), real-time energy consumption information, and automated load management technologies could have on customers' energy consumption behavior.

### *Utility activity*

On March 15, 2010, the DPU approved NSTAR's smart grid pilot program proposal, making it the first pilot approved in the state. NSTAR, the largest investor-owned distribution utility in the state, intends to test a variety of smart grid technologies to evaluate the effectiveness of different approaches in producing reductions in customer peak and average consumption as called for in Section 85 of the *Green Communities Act*. These technologies will be deployed in NSTAR's metering and communications, customer information, automated load management and operational information systems.

NSTAR's $16 million pilot project runs through 2012. Under the approved dynamic-pricing project, NSTAR will provide residential customers in the test communities with programmable thermostats and smart grid in-home technologies that will enable customers to receive near real-time information on energy consumption and prices as well as enable customers to reduce electric load during high-price peak periods through the use of automated load management technologies.

The DPU order also lets NSTAR install smart grid technologies in its underground distribution network. Specifically, NSTAR intends to install sensors and monitoring instrumentation at 500 points on its network grid, including substations, to enhance its supervisory and data acquisition control capabilities. Advanced meters are to be installed at customer-owned, solar photovoltaic installations that would provide real-time measurement and communication of energy flow to help NSTAR monitor, control, and ensure the safe operation of the grid and solar photovoltaic resources that are integrated into the grid.

NSTAR stated that the information collected from these monitoring grid points will provide visibility and operational awareness of its underground networks and help in developing strategies for load balancing, thus increasing the reliability and efficiency of the system. The distribution grid upgrade is expected to be finished by the end of 2012.

NSTAR indicated the benefits of its smart grid pilot program would include the provision of timely pricing and consumption information to consumers, reduced rates for 85 per cent of all hours, when on time-of-use rates, improved reliability of the electric grid and the avoidance of building new power plants to meet peak demand and more responsive load control during critical peak times.

## Texas

### *Market statistics*

| 2009 Data | |
|---|---|
| Net Generation by fuel type | Natural Gas 67%<br>Coal 19%<br>Wind 8%<br>Nuclear 5%<br>Other 1% |
| Installed capacity (MW) | 111,827 |
| Net Generation (MWh) | 396,556,018 |
| Customer Electricity Sales Mix | Residential 38%<br>Commercial 35%<br>Industrial 27% |
| Population (2010) | 25,268,853 |
| Utility Supply Pricing Mechanism | Customers are served by competitive retail electric providers. There is no default service being provided by utilities other than provider of last resort (POLR). POLR service is relatively high-priced, and is intended to be temporary and used only under limited circumstances when a retail electric provider is unable to provide service, or when a customer requests POLR service. |
| 2009 Demand Data (MWh) | • Monthly Average: 35,104<br>• Peak Month: 45,386 (July) |

### *Legislative activity*

The Texas state legislature passed two bills that encouraged the deployment of advanced metering infrastructure technology. House Bill 2129 (passed in 2005) required the Texas Public Utility Commission (Texas PUC) to develop a plan for the deployment of smart metering technology as well as the methodology to recover costs from customers. The Texas PUC was also directed to conduct a biennial study on the efforts of electric utilities to implement and benefit from the advanced metering programs and report its findings to the legislature.

House Bill 3693 (passed in 2007) required electric utilities to administer energy efficiency and demand response programs that would reduce total electricity use and indicated its preference for the deployment of smart metering technology to accomplish this objective. The Texas PUC was directed to consider cost recovery mechanisms that would compensate utilities for administering the programs as well as to establish incentives for utilities that met or exceeded the energy conservation goals. It also included provisions relating to the interconnection of distributed renewable electricity installed by retail electric customers and the provision of renewable energy credits to customers who generate electricity onto the grid.

### *Regulatory activity*

In response to the directive contained in House Bill 2129, the Texas PUC established a rulemaking process to address the matters regarding the deployment of advanced metering and recovery of the related costs from consumers. The result was the adoption of an advanced metering rule in 2007 (Chapter 25.130 of the Texas PUC rules). One purpose of the rule was to promote greater retail electric competition by enabling retail electricity providers to take advantage of advanced metering technologies to develop retail electric services that incorporate dynamic pricing and demand response for residential and small commercial customers. The rule also set out the criteria for cost recovery eligibility of smart metering investments based on technical and functional specifications. While deployment of smart metering technology is voluntary, Oncor Electric Delivery Company LLC (Oncor) and CenterPoint Energy filed deployment plans and received approval for cost recovery.

### *Utility activity*

In December 2008, CenterPoint Energy Houston Electric (CenterPoint) received Texas PUC approval to deploy an advanced metering system across its service territory over a five-year period from March 2009 until 2014. A total of 2.1 million advanced meters are expected to be installed at a cost of $540 million. In October 2009, CenterPoint received federal SGIG funding totaling $200 million for its smart metering/smart grid programs. This funding will enable CenterPoint to accelerate the meter installation by two years. As of August 2010, CenterPoint installed nearly 615,000 meters.

In addition to the deployment of smart metering technology, CenterPoint will be installing power line sensors, remote switches, and other distributed automation equipment to its distribution lines and substations to improve power reliability as well as decrease restoration times in the event of outages, especially those caused by hurricanes.

The city of Austin is undertaking a study to identify ways in which smart grid technologies can accommodate dispersed, renewable energy sources into the distribution grid of its municipally owned utility, Austin Energy. The study, entitled the Pecan Street Project, will investigate the challenges of integrating a multitude of solar energy generation sources, mainly from residential sites, as a viable alternative to relying on centralized power plants. Other challenges to be investigated are the introduction of smart appliances having the capability of turning off or down and plug-in hybrid vehicles.[19]

Dallas-based Oncor Electric Delivery Company LLC (Oncor) received the approval of the Texas PUC to spend $686 million to install 3.4 million smart meters throughout its delivery system by 2012. The deployment will include technologies that can capture consumption data at 15-minute intervals, remotely disconnect and re-connect service, and support a home area network. The home area network will provide consumers with text messages, pricing signals, and load control instructions through the Smart Meter Texas Portal, a joint project by Oncor, CenterPoint, and AEP Texas under the direction of the Texas PUC.

As of June 2010, Oncor installed one million meters throughout its service area.[20] Shortly after deployment, customers began reporting higher than usual bills and claimed their smart meters were overcharging for electricity. In response, the Texas PUC ordered the independent testing of Oncor's installed meters and billing processes. The independent report confirmed the accuracy of the meters but noted that Oncor could have been more diligent in monitoring and analyzing the performance of the meters and more proactive in addressing customers' concerns with the meters. Oncor did not receive any SGIG funding for this project. However, Oncor did secure a $3.5 million grant for a dynamic line rating project, to evaluate technologies that can reduce transmission-line congestion and increase the carrying capacity of its transmission lines.

## California

### *Market statistics*

| 2009 Data | |
|---|---|
| Net Generation by fuel type | Natural Gas 62%<br>Water 19%<br>Others 8%<br>Nuclear 7%<br>Wind 4% |
| Installed capacity (MW) | 70,867 |
| Net Generation (MWh) | 206,183,063 |
| Customer Electricity Sales Mix | Commercial 47%<br>Residential 35%<br>Industrial 18% |

[19] Kate Galbraith, "Deep in the Heart of Texas: A Smart Grid" *The New York Times* (December 3, 2008), online: The New York Times, http://green.blogs.nytimes.com/2008/12/03/deep-in-the-heart-of-texas-a-smart-grid.

[20] Oncor, News Release, "Oncor Reaches 1 Million Smart Meters" (June 2, 2010), online: Oncor News http://www.oncor.com/news/newsrel/detail.aspx?prid=1266.

| | |
|---|---|
| Population (2009) | 37,983,948 |
| Utility Supply Pricing Mechanism | Inclining block rate design established by the California Public Utilities Commission in 2001 for residential customers. Consequently, the three largest utilities have rate structures that charge more per unit of energy as energy usage increases in the billing period. Once smart meters are fully deployed, rate structure expected to change to hourly time-of-use or critical peak pricing for residential customers. For non-residential customers, tariffs that combine time-of-use and critical peak pricing will become the default rate. |
| 2009 Demand Data (MWh) | • Monthly Average: 26,665<br>• Peak Month: 45,994 (September) |

### *Legislative activity*

California established renewable portfolio standards in 2002 under Senate Bill 1078. The renewable portfolio standards program requires electric utilities to increase procurement from eligible renewable energy resources by at least one per cent of their retail sales annually, until they reach 20 per cent by 2010 and made the California Public Utilities Commission (CPUC) responsible for ensuring that electric utilities met the state's renewable portfolio standards targets. Executive orders issued by the governor in November 2008 and September 2009, established a further goal of 33 per cent renewable energy by 2020.

Senate Bill 17, which received the governor's approval on October 11, 2009, mandated that the CPUC, in consultations with the California Independent System Operator and the California Energy Commission, develop and articulate the requirements for a statewide smart grid deployment plan by July 2010. The smart grid deployment plan was to be consistent with, and support the state's energy policy objectives that included the implementation of advanced metering, achievement of the renewables portfolio standard, the reduction of greenhouse gas, introduction of demand response programs and the integration of distributed generation into the electricity grid. California investor-owned utilities with more than 100,000 customers were then required to develop and submit their compliance plans by July 1, 2011.

On June 3, 2010, the California State Assembly passed AB 2514 (California Energy Storage Bill), legislation that will require utilities to acquire and use energy storage systems in an effort to promote the development and commercial use of this emerging technology. The bill would require the CPUC to open a proceeding by March 1, 2012 to establish procurement targets for energy storage systems by December 31, 2015, and December 31, 2020. Proponents of the legislation stated the addition of energy storage systems would lessen the state's dependence on fossil fuel generation to meet peak demand requirements and help achieve the state's renewable energy goals.

### *Regulatory activity*

Prior to the enactment of Senate Bill 17, the CPUC established a number of initiatives promoting the use of smart grid technologies. In 2004, the CPUC directed the three largest investor-owned

utilities (i.e., Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison) to deploy smart meters as a means of expanding the use and availability of demand response programs and implementing dynamic pricing rates.

The CPUC initiated a rulemaking (R08-12-009) in December 2008 in compliance with the requirements of the *Energy Independence and Security Act of 2007*. This rulemaking considered the policies and standards and protocols required for California's investor-owned electric utilities to develop a smart grid system for the state, which would accommodate technologies associated with distributed generation, energy storage, and demand-side programs, as well as plug-in electric vehicles.

On June 24 2010, the CPUC issued its decision on R08-12-009 and ordered the utilities to submit smart grid deployment plans by July 1, 2011. The decision set out the CPUC's requirements and policies regarding technologies to be deployed, privacy standards to be considered, performance metrics to be established and cost allocations to be adopted by the three major investor-owned utilities as they develop their smart grid deployment plans.

Each utility is to follow a common outline in preparing their plan, consisting of a smart grid vision statement outlining uses and benefits of the latest technologies; a deployment baseline indicating the current status of the utility's systems and equipment; a roadmap indicating how it proposes to achieve California's stated smart grid goals; cost and benefit procedures to enumerate and quantify the costs and benefits of smart grid investments; grid and cybersecurity strategies; and metrics to measure utility progress and performance in achieving smart grid goals.

The decision also set out the information requirements that the Smart Grid deployment plans must address, including how the deployment plans link back to the policies contained in Senate Bill 17 and in relevant federal law. The requirement to provide an annual report is another feature of the decision. Each annual report must include information regarding a summary of the utility's deployment of Smart Grid technologies during the past year (July through June) and its progress toward meeting its Smart Grid deployment plan, the costs and benefits of Smart Grid deployment to ratepayers during the past year, current initiatives for Smart Grid deployments and investments, updates to the utility's security risk assessment and privacy threat assessment, and the utility's compliance with North American Electric Reliability Corporation security rules and other security guidelines and standards as identified by the National Institute of Standards and Technology and adopted by the Federal Energy Regulatory Commission.

### *Utility activity*

In response to the CPUC direction to deploy advanced metering technology, Pacific Gas & Electric (PG&E), San Diego Gas & Electric and Southern California Edison filed, and received CPUC approval for their smart metering projects. PG&E is spending $2.2 billion to install 5.3 million electric and 4.2 million gas meters by 2012. As of February 2010, 4.7 million gas and electric meters were in service.[21] San Diego Gas & Electric will be installing 1.4 million electric

[21] PG&E, News Release, "PG&E Responds to USA Today Article About the National Move to a Smart Grid System" (February 25, 2010), online: PG&E Media Newsroom, PG&E Point of View

and 900,000 gas meters by the end of 2011 at a cost of $572 million. Southern California Edison will be spending $1.7 billion to install 5.3 million electric meters by the end of 2012.

Consumers soon became concerned about PG&E's deployment of its smart metering program. Residents in the Bakersfield service area claimed the new meters were malfunctioning and over-reporting usage, resulting in them being overcharged on their electricity bills. Some residents filed a class-action lawsuit against PG&E over the matter.[22] The CPUC hired an independent expert to investigate the accuracy of PG&E's smart meters. The independent expert issued its report in September 2010 and found the meters to be accurate, but determined that PG&E performed poorly in providing customers with the necessary level of detail and education related to its smart meter deployment and technology.

PG&E admitted that technical problems related to the metering installation process in tens of thousands of their smart meters cases contributed to high level of customer dissatisfaction.[23] To correct the issues raised by the residents, PG&E expanded its side-by-side meter-testing program, in which the performance of new meters is measured alongside the meters they will replace and set up a dedicated call centre to handle customer questions regarding smart meters.

## Ontario

### *Market statistics*

| 2008 Data | |
|---|---|
| Net Generation by fuel type | Nuclear 32%<br>Natural Gas 24%<br>Water 22%<br>Coal 18%<br>Wind 3%<br>Other 1% |
| Installed capacity (MW) | 35,781 |
| Net Generation (MWh) | 159,500,000 |
| Customer Electricity Sales Mix | Industrial 51%<br>Residential 34%<br>Commercial 15% |
| Population (2009)[24] | 13,069,200 |

http://www.pge.com/about/newsroom/pgepointofview/20100225/pge_responds_to_usa_today_article_about_the_national_move_to_a_smart_grid_system.shtml.

22 Camille Ricketts, "PG&E refutes suit alleging price-gouging via smart meters" *GreenBeat* (November 9, 2009), online: GreenBeat, http://green.venturebeat.com/2009/11/09/pge-refutes-suit-alleging-price-gouging-via-smart-meters/.

23 Dana Hull, "PG&E details technical problems with SmartMeters" *San Jose Mercury News* (April 27, 2010), online: Consumer Federation of California Press Room http://www.consumercal.org/article.php?id=1292.

24 Statistics Canada, CANSIM, table 051-0001 – "Population by sex and age group, by province and territory", online: Statistics Canada Summary Table, http://www40.statcan.gc.ca/l01/cst01/demo31a-eng.htm.

| | |
|---|---|
| Utility Supply Pricing Mechanism | Residential and small commercial customers are charged seasonal tiered prices under the regulated rate plan approved by the Ontario Energy Board. These rates are reviewed twice a year. Utilities who have been approved time-of-use rates are charging four different prices per day depending on when the electricity is being consumed. |
| 2009 Demand Data (MWh) | • Monthly Average: 17,614<br>• Peak Month: 25,815 (August) |

### *Legislative activity*

On March 28, 2006 the Ontario Legislature passed the *Energy Conservation Responsibility Act*. This legislation established the framework for the installation of smart meters in Ontario homes and small businesses. The government committed to installing smart meters in all homes and small businesses by 2010, a number that is expected to reach 4.5 million.[25] Other features of the legislation include the requirement to establish a province-wide demand side management program having the capability to obtain up to 500 MW in demand response and the creation of a net metering program to allow farmers, small businesses, and consumers that generate renewable electricity to receive credit for the excess power they produce.

The legislation also provided the government with the flexibility to determine the best options for the governance, ownership and regulatory structures of the smart metering initiative as it goes forward. To this end, the government decided to have a central agency take on the responsibility for collecting and managing the meter data from all meters, including the validating, editing and estimating processes as well as producing bill-ready data to be used to invoice customers for their consumption.

On May 14, 2009, Ontario's Bill 150, the *Green Energy and Green Economy Act, 2009* was passed by the Ontario Legislature. The intent of the *Green Energy and Green Economy Act, 2009* is to encourage the development, availability, and use of new renewable energy sources by removing barriers and giving priority to renewable energy projects and to promote a green economy, and with it, the creation of new job opportunities. As well, the *Green Energy and Green Economy Act, 2009* identified energy conservation and efficiency as a priority for the province.

The *Green Energy and Green Economy Act, 2009* introduced feed-in tariffs to promote investments in renewable energy technologies. The feed-in tariffs took the form of standardized prices and long term contracts and were designed to simplify the process for procuring energy from renewable energy sources. The approval process for renewable energy projects was streamlined with the major change being the removal of most municipal government planning approval requirements for renewable energy projects. Transmission and distribution utilities are required, under certain conditions, to provide priority access to renewable energy generation facilities.

[25] Ven Seshadri, "Smart Metering in Ontario" *Metering International*, Issue 2, 2008, online: The Spi Group White Papers, http://www.thespigroup.com/CompanyLiterature/Pdf/SMARTMETERINGINONTARIO.pdf.

The *Green Energy and Green Economy Act, 2009* gave the Ontario Energy Board (OEB) the mandate to facilitate the development of a smart grid electricity system in Ontario. Related to this mandate, transmission and distribution utilities are required to submit plans to the OEB outlining how they intend to develop and implement a smart grid system within their service area. On November 23, 2010, the Minister of Energy directed the OEB to establish a process to facilitate the implementation of a smart grid consistent with the goals and objectives of the *Green Energy and Green Economy Act, 2009*.

***Regulatory activity***

The OEB has the statutory mandate to implement the government's policies of energy conservation, promoting renewable energy sources and implementing technological innovations. In discharging this mandate, the OEB completed a number of initiatives, including the establishment of a simplified connection process for renewable energy generators, standardization of the billing and settlement process for feed-in-tariff generators and the determination of a cost allocation methodology for electricity infrastructure investments.

The OEB also had the responsibility for developing and overseeing the implementation plan that would achieve the government's smart meter installation goals. Ontario has over 80 electric distribution utilities, most of which are municipally owned. The OEB took charge of coordinating implementation of the physical systems (i.e., smart meters and the associated information, communication and technology systems) as well as introducing pilot projects to study the effectiveness of smart metering and time-of-use billing in achieving the government's energy conservation objectives. The OEB's implementation plan included mandatory technical requirements for smart meters and their support systems; the priorities for implementation to meet the government's targets and the regulatory mechanisms for cost recovery.

In August 2010, the OEB determined that time-of-use pricing will become mandatory for electric distribution utilities providing a regulated price plan service to customers and established the timelines for complying with this directive.

The OEB initiated a consultation process in January 2011 to examine technical issues associated with the implementation of a smart grid infrastructure. This consultation was in response to the minister of energy's directive which required the OEB to provide guidance to licensed electricity transmitters and distributors and other regulated entities that propose to undertake smart grid initiatives and activities. The consultation is intended to provide OEB staff with a better understanding of the technical issues associated with deploying smart grid technologies and equipment, so that the OEB could develop the necessary regulatory requirements.

***Utility activity***

To date, Ontario's electric distribution utilities installed over 1.5 million smart meters. The distribution utilities are now required to implement time-of-use pricing for its regulated price plan customers in accordance with the timelines and requirements of the OEB.

Individual utilities are implementing their own initiatives to promote energy conservation and efficiency using smart grid technologies. For instance, Toronto Hydro offers a demand response

program to residential customers with central air conditioning. Under the program, participating customers agree to have Toronto Hydro install a device on the air conditioning unit that will control the energy usage of the air conditioning during periods of peak demand. Similar programs are offered to small commercial customers as well.

## Observations from other jurisdictions

In the United States, at the federal level, smart grid is being developed and funded to create jobs and help with the economic recovery. Acts and regulations were put in place to define the technologies considered to be smart grid and its functionalities and to help in determining what is considered a smart grid investment. Based on the areas supported by *The American Recovery and Reinvestment Act of 2009*, utilities applied for grants through their state commissions. Smart grid initiatives include projects that increase the proportion of renewable energy to meet standards, as is the case of California[26] (which has a goal of 33 per cent renewable energy by 2020), deployment of smart meters and home area networks to increase retail competition where there is no default supplier (Texas)[27] and to accommodate the use demand response programs and dynamic pricing options to promote energy efficiency and conservation (i.e. Colorado, California and Massachusetts).[28]

A number of states launched or concluded initiatives to solicit input and information from the public and industry on smart grid deployment issues during the course of the Inquiry. These initiatives took the forms of inquiries, task forces and proceedings, and were established for the purpose of considering and examining issues and policy matters regarding smart grid development. The California Public Utilities Commission held a rule-making proceeding to determine the technical requirements necessary for the deployment of smart grid technologies. Their decision was issued in June 2010 after nearly 18 months of consultation with stakeholders. The Illinois Commerce Commission established the Illinois Statewide Smart Grid Collaborative in September 2008 for the purpose of developing a strategic plan to guide the deployment of smart grid in the state in a manner that would ensure that customers become the primary beneficiaries of the deployment. The collaborative, which was comprised of members from utility companies, consumer organizations, telecommunications and information systems providers, equipment vendors, energy service providers and the Illinois Commerce Commission issued its report on September 30, 2010.[29] The members noted in their report that a collaborative approach improved the knowledge and understanding of smart grid issues for all stakeholders and should lead to more informed smart grid investment and deployment decisions.

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[26] California Senate Bill 1078,online: http://www.energy.ca.gov/portfolio/documents/SB1078.PDF; and California Air Resources Board, News Release, Release #:10-51, "California commits to more clean, green energy", (September 23, 2010) online: California Air Resources Board, http://www.arb.ca.gov/newsrel/newsrelease.php?id=155.

[27] Texas House Bill 2129 (79R), Section 8.

[28] K. Doran, F. Barnes & P. Pasrich (eds.), "Smart Grid Deployment in Colorado: Challenges and Opportunities" *University of Colorado at Boulder*, June 2010, online: Center for Energy & Environmental Security, http://cees.colorado.edu/sgreport.pdf.

[29] Illinois Statewide Smart Grid Collaborative, "Collaborative Report" (September 30, 2010), online: Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/en/ISSGC%20Collaborative%20Report.pdf.

The Colorado Public Utilities Commission established a proceeding on February 24, 2010 to examine the general concepts of smart grid and advanced metering and to develop policies related to smart grid and advanced metering deployment for the state. The Colorado Public Utilities Commission issued a number of preliminary conclusions in October 2010 and requested participants to comment on additional questions.

The New York State Public Service Commission commenced an inquiry on July 16, 2010 to develop the regulatory policies required to deploy smart grid technologies in a manner that would be cost-effective for utilities and equitable for customers.[30] Over 100 participants, from utilities, consumer organizations, equipment and telecommunications providers and individuals, registered to participate in the inquiry.

In Ontario, the government plan is to reduce the environmental footprint of the electricity sector, by shutting-down the coal-fired generation and increasing the use of renewable energy. To increase consumers' understanding on energy usage and to provide them the opportunity to participate in demand response programs, the government mandated the implementation of smart meters for the entire province.[31] More recently, the Ontario Energy Board initiated a consultative process with industry stakeholders to examine technical issues associated with the implementation of a smart grid infrastructure in Ontario.

[30] New York State Public Service Commission, Case 10-E-0285, Case 09-M-0074 "Order Instituting Inquiry into Smart Grid" (July 16, 2010) online: New York State Public Service Commission, http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={0E389198-D21F-48F4-8718-5FAAEFBF7402}.

[31] Ontario Smart Grid Forum, "Enabling Tomorrow's Electricity System" (February 2009), online: Independent Electricity System Operator, http://www.theimo.com/imoweb/pubs/smart_grid/Smart_Grid_Forum-Report.pdf.

# Appendix 5 – Cost-benefit methodology

## Appendix 5 – Cost-benefit methodology

***This appendix includes a methodology for conducting a cost-benefit study to assist in assessing the potential costs and benefits of different smart meter and AMI rollout scenarios for residential and small commercial customers.***[1]

### Introduction

The Commission requested that participants address a number of questions (see Exhibit 0003.01, Commission Questions 28 through 35) regarding the tools and methods that should be considered in determining the costs and benefits of smart grid investments. The responses indicated that the initial starting point should be a traditional cost-benefit analysis. The Commission then asked a supplemental question (see Exhibit 0131.02, Question 66) concerning the applicability for Alberta of using an evaluation model like the one prepared for the Electric Power Research Institute to assess smart grid investments. Participants stated that the model appeared to be comprehensive with respect to the economic analysis but needed to be modified to take into account Alberta-specific considerations. Participants also acknowledged that there may be a number of societal benefits that arise from the adoption of smart grid technologies and that those societal benefits should be included in the cost-benefit analysis, although no participants offered a methodology to do so. An approach to capturing some of those societal benefits is included in this appendix. Other potential societal benefits such as reductions in $CO_2$ or other emissions are discussed elsewhere in the report.

### Cost-benefit overview

All investments are generally subject to some type of cost-benefit analysis to determine each investment's economic value. Companies typically present a cost-benefit analysis when making a business case for an investment in order to demonstrate that the cost of a particular proposed investment is less than the benefits that will accrue to the company as a result.

Benefits that accrue directly to the party making an investment are called private benefits. Benefits that do not accrue directly to the party making the benefits but are benefits to society in general are called societal benefits. Because the costs are typically incurred before the benefits, and because both the costs and the benefits, but particularly the benefits, are accrued over time, it is the present value of the costs and the benefits that must be compared.

[1] Individual responses to the Commission Questions regarding the approaches to estimating the costs and benefits of smart grid investments can be found on the AUC's website at https://www.auc.ab.ca/eub/dds/EPS_Query/ProceedingDetail.aspx?ProceedingID=598.

## Smart grid investments in Alberta

Smart transmission and distribution technology investments that have already been undertaken by the utilities in Alberta must be considered to have passed such a cost-benefit test. The costs of these investments should be less than the private operational benefits that accrue to the transmission and distribution companies. These investments may also generate indirect benefits for customers, such as lower electricity prices, as a result of more efficient operations. Such investments will continue whenever the costs are less than the benefits. Consequently, smart transmission and distribution technology investments, currently undertaken or being contemplated by the utilities, do not currently require any policy initiatives by the government. It is not necessary to develop a cost-benefit methodology specifically for these investments, as the transmission and distribution companies have already determined how to evaluate these investments and can be expected to continue to evaluate new technologies as they arise.

Industrial and large commercial customers typically have meters that permit hourly pricing that reflects the Alberta power pool price. In order to support the billing, settlement and storage systems designed to function in the competitive generation and retail markets, the distribution companies, the AESO, and the retailers have all established electronic communications links with enough capacity for those purposes and that might be capable of being expanded.[2] These investments in the communications systems were the result of the introduction of competition in the Alberta market, while the investments in the metering passed the traditional cost-benefit test. Smart meter and AMI investments for industrial and large commercial customers, currently undertaken or being contemplated, also do not currently require any policy initiatives by the government. Therefore, it is also not necessary to develop a cost-benefit methodology specifically for these investments, as the distribution companies have already determined how to evaluate these investments and can be expected to continue to evaluate new technologies as they arise.

Currently in Alberta, some residential and small commercial meters support remote meter reading. These meters are connected to the distribution company through analog communications links (power line carrier systems). The costs of these investments were found to be less than the private benefits that accrue to the distribution companies, and that is why they were undertaken.

There may be additional private operational benefits from the deployment of smart meters and AMI, including improved remote meter reading, remote connect and disconnect services, and certain direct demand management programs.[3] Some participants in the Inquiry stated, however, that they did not expect that the private operational benefits from rolling out smart meters and AMI would outweigh the costs. Further evidence of this is that the Alberta distribution companies are unwilling to undertake the investments on their own. In addition, it is apparent

[2] See the Smart meter section of the report and Appendix 7 – Smart metering technologies and related matters for more information.

[3] For a discussion of the private benefits of smart meters, see Edison Electric Institute (prepared by Plexus Research Inc.), "Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act", Chapter III, (September 2006), online: Edison Electric Institute, http://www.eei.org/ourissues/electricitydistribution/Documents/deciding_on_smart_meters.pdf.

that the benefits to Alberta residential and small commercial customers are not considered to be sufficient for customers to be willing to incur the cost of the smart meters and AMI. Otherwise, competitive retailers would be offering a smart meter and multi-period pricing to these customers, but they generally do not.

If the cost of smart meters and AMI exceeds the private operational benefits, which appears to be the case at this time, it is necessary to assess the societal benefits of deploying smart meters and AMI and add the value of those societal benefits to the value of the operational benefits in order to inform the public policy decision. The purpose of this appendix is to outline a cost-benefit methodology to assess all additional private operational benefits and any societal benefits that result from an investment in smart meters and AMI.

## Benefits of smart meters and AMI

The private operational benefits of smart meters and AMI arise primarily as a result of the two-way communication capabilities permitting remote meter reading and related services and the ability to record energy consumption as frequently as every five minutes and support real-time energy pricing. In addition to these private operational benefits, smart meters and AMI can permit direct demand management programs and can provide information that may permit customers to reduce their energy consumption. Demand management programs include direct load control programs with measurement and verification by the company. In-home displays allow customers to view their electricity consumption and prices in near real-time and may result in customers adjusting their consumption of electricity. Information from in-home displays may provide the incentive for customers to reduce their overall consumption, while higher prices in peak periods may cause them to reduce their electricity use during these periods.

BC Hydro has recently presented a business case that includes a cost-benefit analysis for the installation of smart meters and AMI.[4] The benefits, which BC Hydro claims exceed the costs of the meters, result from operational improvements. If these meters were put in place, the result should be a reduction in electricity rates from what they would have been without the smart meters being installed. The Electric Power Research Institute (EPRI) has also recently published a study demonstrating how to calculate the costs and benefits from smart grid demonstration projects.[5] While the main focus of EPRI's study is on the operational benefits from smart transmission and distribution technology, it also includes potential operational benefits from the installation of smart meters and AMI. These benefits are primarily private benefits, however, as they generally accrue to the party making the investment.

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4 BC Hydro, "Smart Metering and Infrastructure Program Business Case" (January 2011), online: BC Hydro, http://www.bchydro.com/etc/medialib/internet/documents/smi/smi_business_case.Par.0001.File.smi_business_case.pdf.

5 The Electric Power Research Institute, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" (January 2010), online: The Smart Grid News (from EPRI), http://www.smartgridnews.com/artman/uploads/1/1020342EstimateBCSmartGridDemo2010_1_.pdf.

Societal benefits from smart meters and AMI arise primarily as a result of multi-period pricing. Multi-period pricing means retail prices for electricity that vary depending on the cost of electricity at various times of day and the year. This results in the efficient use of resources to provide electricity, hence the societal benefit.

The competitive generation market in Alberta allows electricity prices to be determined in the Alberta power pool. While certain operational characteristics of the Alberta power pool may mean that the power pool prices do not precisely reflect the cost of producing electricity, the Alberta power pool prices are related to cost in a general way and are the best measure of cost that is currently available in Alberta. The Alberta power pool prices can be used as a measure of cost when determining time periods and prices for customers in the context of multi-period pricing and other programs such as direct load control permitted by smart meters and AMI.

Multi-period pricing is different from the regulated rate option pricing structure in place today in Alberta, where electricity is priced the same regardless of the season or time of day. The expectation is that customers will respond to these multi-period prices by lowering their consumption during periods of high prices (normally associated with periods of high system demand) and raising their consumption during periods of lower prices (normally associated with periods of low system demand).

These societal benefits do not result simply from a reduction in the use of electricity during peak periods, although such a reduction might well be the consequence of multi-period pricing that increases prices during peak periods and might, in itself, provide some benefits. An objective of a specified load factor or load shape, or an overall reduction in load, however, could impose societal costs as either efficient electricity usage is foregone and production and employment in the economy are curtailed, or, alternatively, peak electricity usage is not reduced enough and electricity is supplied that does not have a value to customers sufficient to cover its cost. While there may be important system reliability benefits from controlling system load, it is the efficient use of resources to supply electricity that will maximize societal benefits.

One of the government's policy objectives is the promotion of wise energy use. The Commission considers wise energy use, for the purpose of examining smart meters and AMI, to be the efficient use of energy made possible by operational efficiencies and the maximization of societal benefits from the efficient use of resources to supply electricity.

The decision whether to deploy smart meters and AMI and, if so, how to deploy them, depends on the unique characteristics of the jurisdiction in which the deployment is being considered and the unique circumstances of each distribution company. Not all of the potential benefits of smart meters and AMI can necessarily be realized in all jurisdictions or by all companies. Furthermore, the decision to deploy smart meters and AMI does not need to be an all-or-nothing decision. Smart meters and AMI could be deployed only for some customers in certain areas. In Alberta, there are a number of unique characteristics that must be addressed when considering smart meter and AMI deployment. These unique characteristics are described in Smart meter section of the report.

One characteristic of the Alberta electricity market, the presence of unregulated competitive retailers, is of particular importance in evaluating smart meters and AMI and the related issues raised in this appendix. While multi-period pricing could be imposed on customers purchasing electricity under the regulated rate option, it cannot be imposed on customers of competitive retailers if the competitive retailer offers a flat rate option or a rate that is different from the multi-period pricing imposed on the regulated distribution company. Similarly, programs to directly control customers' loads, and other load management programs or customer information programs, could potentially be imposed on customers using the regulated rate option but not on customers of the competitive retailers.

The consequence of this is important for evaluating any of the pricing or demand management programs enabled by smart meters and AMI. Regulated rate option customers who do not like multi-period pricing or demand management programs can simply switch to a competitive retailer that does not require that customers purchase electricity under such rates or that they participate in similar demand management programs. Of course, if these pricing and demand management programs are unpopular, competitive retailers will have a strong incentive to offer alternative programs. While the remaining customers may have a significant response to multi-period pricing, especially in peak periods, and may have a strong response to any demand management programs, these will in effect be customers who are voluntarily participating because their bills will go down or because the private benefits to them for whatever reasons are substantial. They will not be representative of customers overall, however, and their behaviour cannot be used to predict the behaviour of a broader group of customers. Furthermore, there may be so few of these customers voluntarily participating that even though their response is individually significant, the absolute response of the group in the context of the electricity system might be minor.

Nevertheless, in the competitive Alberta generation market, what might seem like a minor response could actually result in a significant drop in the wholesale price. This is because the system marginal price can rise dramatically in a short period of time as a new generation source, such as a peaking plant, bids a high price into the market. If residential customers with smart meters were to participate in demand response programs offered by retailers, the demand for that increment of supply could be curtailed and a significant wholesale price reduction for customers could result.

## Cost-benefit methodology for smart meters and AMI

Carrying out a cost-benefit analysis requires the measurement of all of the additional costs of deploying smart meters and AMI and all of the additional private and societal benefits that result for the group of customers being studied. Following is an overview of an eight-step methodology for a cost-benefit analysis designed to capture these costs and benefits. While this methodology could be used for any customer group, in the Alberta context the cost-benefit methodology would be applied to residential and small commercial customers or a sub-group of those customers.

Step One: Determining the smart grid programs. Smart meters and AMI provide a distribution company, retailers, and customers with a variety of potential operational and other benefits. Therefore, the first step of the cost-benefit analysis is to determine which programs will be deployed and the specific characteristics of each program that might generate benefits.

Step Two: Determining time periods. For direct demand management programs, multi-period pricing, and other programs enabled by smart meters and AMI, it is necessary to know when the various pricing periods occur. This is the case because some costs and benefits may be correctly attributed to particular time periods rather than to customers or electricity use overall.

While it is possible to have real-time pricing for these programs, with the price faced by residential and small commercial customers varying instantaneously or in fifteen-minute or hourly intervals, it is also possible and perhaps desirable to design a price structure with fewer time periods that may be more easily understood by customers. Statistical analysis can be used to group hours together in which the Alberta power pool prices are similar, and to determine groups of hours that are different from each other based on the Alberta power pool prices during the various hours. The result of this analysis would likely be several time periods that would vary over the day and over the year. For instance, there might be a peak season and an off-peak season, each comprised of certain months. There could also be a shoulder season. Three seasons might entail a winter season, a summer season, and a spring-fall season. Within each season, there might be three or four time periods during each weekday, with weekend time periods established differently. The extent to which the Alberta power pool prices vary would determine the extent to which prices would vary for customers across these different time periods.

One consideration in establishing time periods, using the results of the statistical analysis, is whether or not residential and small commercial customers will be able to respond to the time periods and pricing information provided. Real-time pricing sounds good, but residential and small commercial customers are unlikely to spend their days in front of a pricing display and then run around turning appliances and lights off and on in response to price changes. While some customers may choose to incur the expense of automatic devices that will turn appliances off and on in response to price changes, they may not choose to live with this automatic

interference with their comfort and convenience.[6] What is more likely to be successful is that there are two or three time periods during the day with pre-determined hours and prices. Customers will know these time periods and prices, just as they do for other purchases, and may adjust thermostats and appliances in response to these different prices. Examples of such pricing in other industries includes early-bird parking, lower airline ticket prices for off-peak travel, weekend and off-season car rental prices, weekend and off-season hotel rates, evening and weekend long distance telephone prices, and matinee and evening movie and theatre prices.

Step Three: Determining the cost. The next step is to determine the additional cost of deploying the smart meters and associated AMI that are required for each of the programs identified in Step One for each of the customer groups under study. The cost will include the stranded investment related to the existing meters that are removed as well as any increment in the price of the smart meters compared to the meters that might otherwise be installed. The Commission expects, based on what it has learned, that this increment will disappear shortly. Incremental installation costs must also be included. To this must be added the cost of the AMI (or upgrades to existing AMI) and the communications links from the meters to the distribution company business offices necessary to implement the smart meter features, including multi-period pricing. Another cost is the ongoing operation and maintenance costs of the smart meters and AMI, to the extent that they exceed the operation and maintenance expenses of the meters currently installed. Individual programs may have additional specified costs. For example, a direct load control program that involves smart meters communicating with appliances will have costs associated with this communication and control function. The present value of these costs should be calculated.[7]

Step Four: Estimating elasticities. Price elasticities of demand are required in order to predict the amount by which consumers will increase or decrease their electricity consumption in each time period in the face of multi-period pricing in response to decreases or increases in prices compared to the current prices in each time period. They can also be used to predict customers' response to any other price change that might result, for example, from a demand management program. While an overall price elasticity of demand can determine the overall reduction in consumption by consumers in response to an overall increase in price across all time periods, in order to evaluate multi-period pricing, price elasticities of demand are required for each proposed time period. Price elasticities of demand simply tell what percentage change there will be in the amount of electricity purchased by consumers in response to a certain percentage change in the price. These elasticities will be required for each class of customer or group of customer under study (for example, small commercial, large residential, small residential) and for each time period (for example, summer and winter critical-peak, peak, and off-peak) that is being considered for multi-period pricing. For example, it would be necessary to know the elasticity for large residential customers for the critical-peak, peak, and off-peak periods in the summer and in

[6] It is possible that in the future appliances may be designed with such communication and control systems built into them, but this is not the case today, and in any event it would take some number of years until most appliances have been replaced.

[7] The useful life of smart meters may be shorter than the useful life of the electromechanical meters that they replace, and therefore annual depreciation charges would be greater. This will be accounted for in the present-value calculation as the benefits that are counted accrue over fewer years, but the result will be higher annual charges for the smart meters and AMI.

the winter (six periods in total) in this illustration in order to know how electricity use would change in each of these periods as the price changed from the current price. There is also the possibility of real-time pricing, in which the price paid by customers varies continually, but in this case it would still be necessary to use an elasticity for broader periods to determine how customers would react to continual price changes because instantaneous elasticities do not exist. The calculation of these elasticities is sometimes referred to as a demand response study.

There are three primary options to estimate price elasticities of demand for Alberta customers: use historical data, consider price elasticities of demand estimated in other jurisdictions, and conduct a pilot study in Alberta. Using historical data requires price and usage data for the different groups of customers for the time periods under study over a period of years. Such data may or may not be available for Alberta and for individual retailers. Even if all the required data were available, it might be preferable to use price elasticities of demand that were already calculated for other jurisdictions that have similar customer and system characteristics as Alberta.[8] Alternatively, the Government could conduct a pilot study, which would allow the measurement of the various price elasticities of demand for the different customer groups. Care must be taken in the design of such pilot studies to avoid biases as a result of participants' behaviour being affected by their participation in the study or when participants are permitted to volunteer for the study.[9] In addition, the changes in electricity use can be calculated for a range of elasticities in each time period in order to understand the sensitivity of the benefit calculations to the elasticities and to permit alternative benefit calculations for different expected elasticities.

<u>Step Five: Combining elasticities, prices, and electricity use</u>. To estimate the effect of multi-period pricing, or a general increase or decrease in price as a result of a demand management program, the estimated elasticities are next combined with price and usage data for each group of customers in each time period under study. It is necessary to know the current electricity use in each time period for each group of customers, the current price, and the anticipated price that would be permitted by rates more closely reflecting costs and enabled by the investment in smart meters and AMI. The elasticities will tell how much electricity use will increase or decrease in each time period for each group of customers as a result of the new prices. This analysis can be performed for alternative prices and alternative elasticities in order to understand how the benefits vary under different conditions or assumptions.[10]

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[8] A summary of price elasticities from 15 pilot and other studies can be found in Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity: A Survey of 15 Experiments," *Journal of Regulatory Economics*, Volume 38, Issue 2, August 31, 2010. Because of the unique competitive retail market in Alberta, however, such elasticities may be misleading when applied to Alberta because of customers' ability to switch to a competitive retailer.

[9] For a discussion of some of the issues surrounding the design of pilot studies, see, for example, Ahmad Faruqui, Ryan Hledik, and Sanam Sergici, "Piloting the Smart Grid," *The Electricity Journal*, Volume 22, Issue 7, August/September 2009.

[10] While a simulation using aggressive elasticity estimates can show that the average customer might expect a small bill reduction as a result of multi-period pricing (see, for example, Ahmad Faruqui and Lisa Wood (prepared for the Edison Electric Institute), "Quantifying the Benefits of Dynamic Pricing in the Mass Market" (January 2008), online: Edison Electric Institute, www.eei.org/ourissues/electricitydistribution/Documents/quantifying_benefits_final.pdf).It is also the case that estimates for Toronto Hydro suggest that as many as 80 per cent of customers may have experience a bill

Step Six: Determining benefits. For each program identified in Step One, the associated benefits must be determined. These benefits will include private operational benefits, private benefits for residential and small commercial consumers, and societal benefits. In all cases, these must be only the additional benefits that result from the deployment of smart meters and AMI.

The primary private operational benefits from the deployment of smart meters and AMI fall into two categories: avoided metering costs for meter reading, connects and disconnects, and the value of improved outage avoidance and restoration. Private benefits to customers must be quantified and added to other private and societal benefits. These benefits to customers result from the ability to have additional information and load control opportunities from in-home energy use and price displays, additional pricing options, and other similar programs.

As noted above, it does not appear that private operational and customer benefits exceed the cost of deploying smart meters and AMI for most residential and small commercial customers, since there is not a groundswell of demand for the services they can enable. It is possible, however, that a cost-benefit analysis could find that these benefits do now or will soon, as technology costs decline, exceed the costs. If so, there is no need to continue with the analysis. If the cost-benefit analysis does not find that the operational and private benefits exceed the costs, then societal benefits must be considered. While societal benefits may derive from several sources, it is multi-period pricing that prices electricity closer to the cost of the resources being employed that is the most important societal benefit.

To see how mandatory multi-period cost-based pricing leads to benefits for society, the following example is useful. Retail prices for residential customers might currently be 10¢ per kilowatt hour all day and all night. Costs, however, in terms of resources used, might be 20¢ per kilowatt hour during the day and 5¢ at night. Moving to prices that reflects these costs has the following benefit for society. During the day, customers currently use "too much" electricity. They use electricity for uses that have a value to them as low as 10¢ per kilowatt hour when the electricity uses 20¢ worth of resources to supply. The electricity has a value to the customer that is up to 10¢ less than the resources used to supply it. When faced with a cost-based price, the elasticity will tell how much these customers will decrease their use. Each kilowatt hour of reduced consumption has a gain to society of up to 10¢ -- the difference between the 20¢ worth of resources that were used to generate the electricity and as little as the 10¢ in value that consumers received. This reduction in electricity use results in a more efficient use of resources to society. The 20¢ worth of resources saved can be used to produce something that gives consumers 20¢ worth of value and not as low as 10¢. The opposite happens at night in this illustration as customers are faced with a cost-based price of 5¢. Now customers will increase their electricity use so that they can make use of all of the electricity with a value of at least 5¢ per kilowatt hour, which is the actual cost in terms of resources of providing the electricity.

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increase as a result of time-of-use pricing (Karen Howlett, "Ontario hydro's smart meters give dumb results: critics," *The Globe and Mail (print edition)*, September 15, 2010, online: The Globe and Mail, http://www.theglobeandmail.com/news/national/ontario/ontario-hydros-smart-meters-give-dumb-results-critics/article1707808/.).

Society gains up to 5¢ per kilowatt hour for each of the kilowatt hours of increased consumption as resources are used to provide electricity that has a value of at least 5¢ to consumers instead of consumers consuming electricity as if it cost 10¢.[11]

The benefits to society from the more efficient use of resources in the generation of electricity will be greater when the price elasticities are higher. Higher price elasticities mean that consumers will respond more to changes in price, reflecting a greater inefficiency in use from the non-cost-based prices. More kilowatt hours will be used more efficiently when price elasticities are higher. The benefits will also be greater when existing prices are further away from cost. In Alberta, the Alberta power pool price, as a representation of cost, for each time period can be compared to existing prices that customers pay to gauge the magnitude of any benefits that might result from retail prices that are better related to cost. Benefits to society will also be greater for customers who use larger amounts of electricity. As these customers adjust to prices based on the Alberta power pool prices, their changes in use will be greater than for smaller customers with the same elasticities. This will result in a greater benefit to society as more resources will be used more efficiently. The societal benefits will also be greater as more customers are subject to multi-period pricing. If fewer customers participate, total benefits will be correspondingly reduced. The presence of competitive retailers, and customers' ability to switch to them, can limit the number of customers participating in multi-period pricing. In all of these cases, the greater the inefficient use of resources initially, the greater are the potential benefits to society from the more efficient use of resources in response to multi-period prices.

Step Seven: Other benefits. In order to determine the total benefits from smart meters and AMI, it is necessary to consider if there are any additional societal or private benefits that should be included. Two additional potential societal benefits that are sometimes mentioned are a reduction in greenhouse gases and other emissions and the creation of jobs. Measuring job creation is notoriously difficult, and, for example, the EPRI study states "These are difficult to estimate and we do not address them in this report."[12]

Estimating the effect on emissions is complex. Multi-period pricing and other load control or demand management programs will result in a flattening of daily and annual loads. The extent to which this will happen can be estimated using the elasticities and the information on usage as described above. In the short run, this change in load will cause a decrease in the operation of peaking facilities and an increase in the operation of base load generating facilities if capacity is available. In the longer run, more base-load plants will be constructed if the capacity is needed. Given the fuels used in base-load and peaking generation, the effect on emissions can be estimated. To this must be added any overall increase or decrease in electricity use. Off-peak electricity use may increase by more or less than any reduction in peak use; this will depend on relative elasticities and quantities of use in peak and off-peak periods. In addition, operational

[11] The economic foundation for this analysis, with particular applications to utility pricing, received one of its most lucid and cogent explanations in Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions, Volume I, Economic Principles*, Chapters 3 and 4, John Wiley & Sons, 1970.

[12] The Electric Power Research Institute, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects" (January 2010), pages 2-17, online: The Smart Grid News (from EPRI), http://www.smartgridnews.com/artman/uploads/1/1020342EstimateBCSmartGridDemo2010_1_.pdf.

efficiencies resulting from smart meters may lower prices to customers, thereby increasing electricity consumption. The positive or negative benefit from any net change in emissions would need to be quantified and a dollar value placed on it.

Step Eight: Comparing the costs and benefits. The final step is to compare the total net present value of the all of the benefits to the total net present value of all of the costs for installing smart meters and AMI for the programs in Step One and for the groups of customers included. If the total net present value of the benefits exceeds the total net present value of the costs, then the investment should be undertaken. Because it is likely necessary to include societal benefits to justify undertaking smart meter and AMI investments, this may require a smart meter policy on the part of the government or a change in legislation permitting the inclusion of the value of societal benefits in regulatory assessments of just and reasonable rates.

In the case where the total net present value of the benefits do not exceed the total net present value of the costs, it is possible to reconsider the cost-benefit study to determine if there are groups of customers for whom the benefits do exceed the costs. For example, the results of the cost-benefit study may be different for large residential customers than for residential customers overall, as the greater level of use of electricity will generate greater benefits than for residential customers overall. Finally, an analysis can be undertaken to determine how sensitive the benefit calculations are to the price elasticities, the number of time periods, the number of customer classes, and any other components of the benefit calculations.

## Related issues

Some participants in the Inquiry (representing large industrial customers) suggested that they be allowed to bid a reduction in electricity use into the Alberta power pool in the same way that generation facilities bid energy generation into the power pool. If the price faced by customers does not reflect the Alberta power pool price, then there could be societal benefits from customers bidding a reduction in electricity use into the pool. This effectively moves the price closer to the Alberta power pool price, as is the case for the multi-period pricing permitted by smart meters and AMI for residential and small commercial customers, and the benefit calculation is similar. For example, if the cost of generating electricity is 30¢ per kilowatt hour during a critical-peak period, there would be a benefit to society from paying customers up to 30¢ per kilowatt hour minus the retail price of electricity the customer pays not to use electricity during the critical-peak period. This might be the case if the price that customers paid was significantly different from the Alberta power pool price. The benefit to society would be the difference between the cost of the electricity (30¢) and what the customer is paid for each kilowatt hour curtailed.

On the other hand, if the cost of electricity during the critical-peak period is 30¢ per kilowatt hour, there would be no benefit to society in paying customers more than 30¢ per kilowatt hour minus the retail price of electricity the customer pays to curtail their demand. The benefit to society in this case would actually be negative, a societal cost.

The government, however, might have an objective of a specified reduction in electricity use, either overall or during the peak period. This could be a result of environmental considerations or, for example, to avoid the construction of new transmission lines. In such a case, the government could identify the options for achieving such a reduction in electricity use and determine the cost of each alternative. These options might include multi-period pricing enabled by the installation of smart meters and AMI, direct control of residential appliances, or bidding capacity into the power pool at prices that exceed the Alberta power pool price minus the retail price paid by the customer. For each option, there will be costs in addition to the cost of installing meters to enable multi-period pricing, for example, or direct load control equipment. The other costs that must be considered might include lost employment and production or increased emissions from a change in the electricity generating mix. Considering all of the costs of each option as well as all of the benefits is also a form of cost-benefit analysis.

# Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels

## Appendix 6 – Smart grid technologies at the generation, transmission and distribution levels

***This appendix addresses some of the smart grid technologies that can potentially be employed at the generation, transmission and distribution levels of the grid. It is not intended to be a complete survey of these technologies but does provide some background on the technologies frequently cited by parties in the Inquiry.***[1]

### Smart grid technologies used in generation

#### *Integration of wind power generation*[2]

There are significant challenges related to the large-scale integration of wind generation due to its variable nature and intermittent behaviour, and the fact that it is often located in relatively remote regions. There are many industry groups, research organizations and universities working on international initiatives to address the challenges associated with the large scale integration of variable generation.[3]

System operators employ decision support systems which include a complex arrangement of systems, tools and procedures that are used to ensure that the electric system and wholesale markets are operated reliably and in a fair and consistent manner. These mechanisms must be modified and supplemented to provide the operator with displays and tools that incorporate wind power forecasts and wind power management in day-to-day operations.[4]

Accurate wind power forecasting tools can help the system controller maintain the critical balance of supply and demand of electricity by indicating the timing and amount of other measures required to offset the inherent variability of wind power. A wind power forecast can also provide valuable information to market participants who can provide the necessary resources (operating reserves) to offset the variability in the wind generation output. Longer term forecasts can also provide information to market participants regarding potential periods of excess generation which may be used to plan generator maintenance.

A wind power facility SCADA system would typically connect the individual turbines, the substations and the meteorological stations to the system control centre central computer through a communications network. This would allow the system operator to obtain the data to create centralized wind power forecasts and monitor the behaviour of the individual wind turbines and

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1 For further information, see the resources set out in Exhibit 203: for example, Illinois Statewide Smart Grid Collaborative, "Collaborative Report" (September 30, 2010).

2 See Appendix 3 for a discussion of the AESO's activities in this area.

3 The North American Electric Reliability Corporation, "Special Report: Accommodating High Levels of Variable Generation" (April 2009), online: NERC, http://www.nerc.com/files/IVGTF_Report_041609.pdf.

4 The Alberta Electric System Operator, "AESO Recommendation Paper - Implementation of Market & Operational Framework For Wind Integration in Alberta" (March 2009), page 44, online: AESO, http://www.aeso.ca/downloads/WI_Paper-_Final.pdf.

also the wind farm as a whole on a real-time basis in order to determine what corrective action, if any, needs to be taken. The local SCADA system will also typically record energy output and availability which provide an operating record for performance monitoring or warranty and maintenance requirements for the owner of the wind power facility.

***Energy storage***

Energy storage technologies can be used to store electricity produced by large-scale renewable generation sources that might be otherwise unused or curtailed. In many regions, rapid installation of wind power has created over-generation scenarios where high winds at night during times of low load create more energy than can be absorbed by the system. Energy storage technologies can be used to store and deliver this energy during other load periods. Energy storage technologies may also be used to counter large wind ramps (up and down) on the grid and avoid curtailment or wind generation power limiting.

There are three main types of energy storage:[5] battery storage, compressed air energy storage and pumped hydroelectric storage. The main characteristics of energy storage devices are the energy density (the amount of energy that can be supplied from a storage technology per unit weight) and the discharge time (the period of time over which an energy storage technology releases its stored energy). These technologies can be used for power quality applications as well as for energy management applications or for both purposes. Recent advances in storage technologies also make them a candidate for providing ancillary services such as spinning reserve, load frequency and voltage regulation, black start operation and other applications. Figure 1 illustrates different types of energy storage devices and some of their characteristics.

Battery storage[6] technologies include different types of batteries and super-capacitors. Batteries are made of stacked cells where chemical energy is converted to electrical energy and vice versa. They are rated in terms of their energy and power capacities, which for most types are fixed during the battery design. Some of the various battery types are available commercially on a small scale, while others are still in the experimental stage. Examples of battery technologies include nickel batteries, lithium batteries, lead-acid batteries, flow batteries, metal-air batteries and sodium-sulphur batteries.

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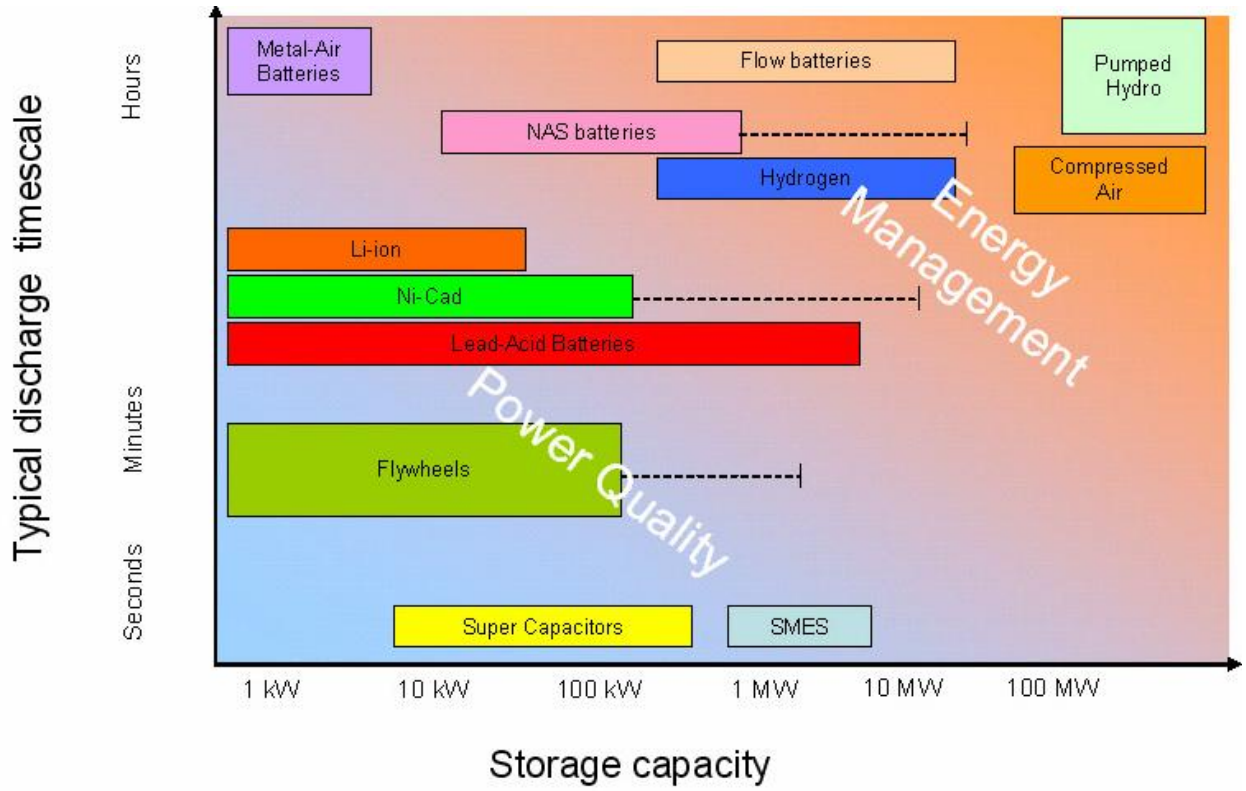
[5] Dr. Chris Naish "et al", "Outlook of Energy Storage Technologies" (2008), page 3, online: The European Parliament Policy Department, Economic and Scientific Policy, http://www.storiesproject.eu/docs/study_energy_storage_final.pdf.

[6] K.C. Divya, Jacob Ostergaard, "Battery energy storage technology for power systems – An overview", (4 April 2009), *Electric Power System Research*, Volume 79, Issue 4, page 512.

**Figure 1: Typical storage capacity versus discharge times for energy storage technologies**[7]




Note: SMES denotes Superconducting Magnetic Energy Storage

A compressed air energy storage facility[8] takes excess energy from a power plant or renewable energy and uses it to run air compressors, which pump air into underground salt or limestone caverns or containers where it is stored under pressure. When required, the compressed air is drawn from the cavern and utilized in a gas turbine to generate electricity. This process results in a reduction in gas consumption of up to 60 per cent relative to generating the same amount of electricity directly from gas. The electricity to compress the air can be purchased at low cost from the power grid at off-peak times and used to generate electricity in high demand periods.

Compressed air technology is mature and it is one of the lowest-cost per unit capacity and the simplest energy storage technologies. It can provide a high storage capacity (50-300 MW) and the storage period is longer when compared with other storage technologies due to the fact that losses are relatively small. Compressed air energy storage technologies can also be directly

[7] Dr. Chris Naish "et al", "Outlook of Energy Storage Technologies" (2008), page 4, online: The European Parliament Policy Department, Economic and Scientific Policy, http://www.storiesproject.eu/docs/study_energy_storage_final.pdf.

[8] Dr. Chris Naish "et al", "Outlook of Energy Storage Technologies" (2008), page 19, online: The European Parliament Policy Department, Economic and Scientific Policy, http://www.storiesproject.eu/docs/study_energy_storage_final.pdf

integrated with wind farms to store power generated in off-peak periods from these energy sources.[9]

Drawbacks to this technology include the reliance on geological structures as well as environment impacts that might result from the use of underground formations. The deployment of this technology is highly dependant on the presence of suitable locations for the underground air storage. Currently there are two commercial compressed air electricity storage facilities in the world. The first one was built in Germany in 1978 and the second in Alabama, US in 1991. A third plant is planned for construction in Ohio, US and it will be the biggest with a capacity of 2,700 MW.[10]

Pumped hydro storage[11] is the most widespread energy storage technology used in the world. During low-cost off-peak periods electric power is used to pump water from a lower elevation reservoir into a higher elevation one. When needed, the water from the highest reservoir is released through turbines and can generate electricity in less than 60 seconds. Underground pumped storage uses flooded mine shafts or other cavities to store the water. The system can be integrated with wind turbines or solar panels to help pump the water and increase the overall efficiency. A pumped hydro storage facility is, however, relatively expensive to build. It does not produce energy and is actually a net user of energy due to the losses incurred during the pumping process.

The three storage methods discussed above differ in capacity, maximum usable storage time and most importantly, implementation and running costs. Actual implementation of these technologies in the context of integration of large-scale renewable generation sources is relatively limited. Compressed air energy storage and pumped hydro energy storage systems do lend themselves to larger scale implementation however they require significant investments and cover large geographic areas. Battery storage has been implemented to provide back-up power in emergency situations for relatively short periods of time.[12] Research and development is being conducted on the development of modular battery storage systems that can be used in a wide range of application.[13]

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[9] Electricity Storage Association, "Technologies – CAES", online: http://www.electricitystorage.org/ESA/technologies/caes/.

[10] Electricity Storage Association, "Technologies – CAES", online: http://www.electricitystorage.org/ESA/technologies/caes/.

[11] Electricity Storage Association, "Pumped Hydro", online: http://www.electricitystorage.org/ESA/technologies/pumped_hydro/.

[12] ABB Inc., "ABB Constructs World's Largest Battery Energy Storage System in Fairbanks, Alaska" (2004), online: ABB,http://www05.abb.com/global/scot/scot270.nsf/veritydisplay/2425f2005afa833585256e830069f0d5/$File/410007_BESS-Alaska.pdf.

[13] ABB Inc., "2MW PCS Unit for BESS Applications" (2010), online: ABB, http://www05.abb.com/global/scot/scot232.nsf/veritydisplay/111b2cefdba457b185257773006d1c8f/$File/2MW_PCS_BESS2010.pdf.

## Smart grid technologies used in transmission

### *Dynamic equipment ratings*[14]

Advances in sensor technology and digital communication systems are making it possible for grid operators and transmission facility owners to continuously monitor and instantaneously collect and analyze information on the status of the transmission system and its components. Knowing that a transmission line or substation component is in imminent risk of failure or that the transmission system is approaching stability limits can allow actions to be taken more quickly and proactively to prevent a disturbance or an outage, contain a disturbance, or reduce the duration of an outage. The rating of transmission components is dependent upon a number of factors such as ambient weather conditions, previous loading history and component configuration and to accommodate this complexity, static ratings are usually based on conservative assumptions of these factors. In principle, higher ratings may be achieved if more precise real-time knowledge of a component's condition can be obtained using sensors.

For example, transmission circuit thermal ratings are generally determined by a static rating that is calculated using worst-case weather conditions that may not adequately represent the actual temperature, wind speed and direction, or solar radiation which directly affect the thermal capacity of a transmission line. The static ratings generally apply for extended periods but transmission operators may be able to exceed the static rating by 10 to 20 per cent for brief periods during system emergencies based on system operations procedures. Use of dynamic ratings takes into account changing weather conditions and dynamic thermal ratings can provide the operator with an extremely accurate real time view of line conditions allowing the system operator to maximize power transfers on the line[15] without risking actual overload.

Dynamic ratings are calculated using similar techniques to the methods used for static rating calculations. The difference, however, is that dynamic ratings are based on real-time measurements or near-term predictions of weather conditions and circuit loading as well as real-time measurement of component parameters such as temperature, rather than on worst-case assumptions. Unlike static ratings, dynamic ratings are valid for a limited time. There are various approaches and technologies for dynamically monitoring the thermal state of transmission lines including dynamic ratings based on; weather conditions, conductor temperature, and conductor sag/tension. The application of dynamic line ratings could provide the operator with better situational awareness and management of real-time and post-contingency power flows during high load periods, planned outages and system emergencies that otherwise could exceed static ratings.

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[14] J. Mayadas-Dering, L. Hopkins & A. Schuff, "NY UTILITY Examines Integrating Dynamic Line Ratings" (July 2009), online: Electric Light & Power, http://www.elp.com/index/display/article-display/366120/articles/utility-automation-engineering-td/volume-14/issue-7/features/ny-utility-examines-integrating-dynamic-line-ratings.html.

[15] Where transmission line flows are limited by thermal capacity rather than voltage or stability limits.

In addition, wind generator facilities may be connecting to the system faster than the transmission system can be developed. The thermal capacity of overhead transmission increases as the wind velocity increases. During high wind conditions, the thermal capacity of conductors could therefore be increased through the use of dynamic ratings rather a fixed rating, thereby possibly reducing curtailment of wind generation due to transmission congestion. The dynamic rating of the transmission line (and actual real time capability) can also be lower than the traditional line rating due to weather conditions (no wind and high temperature), therefore use of this technology could also mitigate potential damage to a transmission line. Dynamic ratings and real-time monitoring of transmission lines are becoming important tools in facilitating renewable energy integration in a reliable manner.

Although dynamic line rating technologies show considerable promise, there are practical issues that need to be overcome with the large scale implementation of these new technologies including; incorporation of large amounts of data in existing control centres and creation of useful operator displays, the reliability of the new technologies, the reliability of communication links and acceptance of operators and asset managers. The recent AESO and AltaLink pilot project confirmed that there were various implementation issues with the technology including reliability issues with the device and the need to incorporate dynamic ratings in operator displays and procedures (AESO and TFOs). This confirmed that additional research is required before pursuing large scale deployment of this technology in Alberta.

Substation transformer operation is also often limited by thermal constraints due to localized hot spots on transformer windings that can result in insulation breakdown. Sophisticated sensing and monitoring tools are now commercially available that combine different temperature and current measurements to dynamically determine temperature hot spots and transformer capacity.

***Phasor measurement units***[16]

Synchrophasors, also known as phasor measurement units (PMUs), are considered to be important new sensing devices because they can provide a more complete and synchronized portrayal of the operating health of the transmission grid. A PMU measures voltages and currents at multiple locations on the transmission grid, up to 30 times a second to provide an accurate time-stamped set of information that can be used to assess system conditions, dynamic and wide area performance of the grid.

Recent industry efforts have focused on developing a variety of applications, including improvements to operator situational awareness, system stability and event analysis, validation of power system models and state-estimation processes and on-line stability assessments.[17] At a high level, deployment of PMUs throughout the transmission grid could enable transmission

[16] U.S. Department of Energy, "Smart Grid System Report" (July 2009), page 43, online: http://www.oe.energy.gov/DocumentsandMedia/SGSRMain_090707_lowres.pdf.

[17] State estimation calculates the voltage magnitudes and angles at all the buses of the power system and it forms the basis for the other Energy Management System functions such as security analysis, voltage stability analysis, optimal power flow, etc.

lines to be loaded closer to their acceptable physical thermal capacities. Currently, 27 PMUs have been installed in Alberta, over 150 PMUs have been installed in North America, and over 850 additional PMUs will be installed over the next three to five years as part of the U.S. DOE Smart Grid Investment Initiative.

### *Advanced power electronics and HVDC technologies*[18]

Electric power utilities have deployed advanced power electronic technologies and Flexible AC Transmission Systems (FACTS) technologies for a variety of applications. These applications include dynamic reactive power support to ensure acceptable voltages during system events and series compensation to effectively increase line capacity without incurring large capital expenditures.

FACTS were invented over thirty years ago in response to the need for rapid dynamic response to issues on the transmission grid. The technology has evolved significantly since the 1970s due to rapid advances in high voltage power electronics, such as switches, inverters and controllers, making it possible for grid operators and facilities owners to more precisely control the flow of electricity over the transmission grid. FACTS devices are capable of limiting transmission line power flows. Advanced power electronics may also provide ride-through capability when faults occur or large motors start. While preventing low voltage events and subsequent loss of load is a common application, advanced power electronics can also mitigate high voltages due to loss of loads.

FACTS can also support the integration of variable generation resources by providing voltage support and control in areas where older wind generators may not have fault ride through capability.[19] In the future, advanced power electronics may also play an important role in effectively combining storage, which is usually DC, with renewable energy resources. Power electronics can therefore address two of the major challenges associated with integrating variable resources: variability and control. FACTS with storage may also be used for generation and ancillary service applications (spinning reserve, frequency regulation and load following) and transmission system applications (dynamic voltage regulation and power flow control, transmission line stability, wide area power quality).

A comprehensive system study is required to determine the appropriate FACTS application on a case-by-case basis. A brief summary of how these technologies can be used to address a variety of transmission issues are shown in Table 1:

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[18] Siri Varadan, "The Transmission is Getting Smarter with Advanced Power Electronics" (October 26, 2010), online: Smart Grid News, http://www.smartgridnews.com/artman/publish/Technologies_Transmission_News/Transmission-is-getting-smarter-with-advanced-power-electronics-3189.html.

[19] Low Voltage Ride Through (LVRT) is the capability of an electric device, particularly a wind generator, to remain interconnected to the power system when the voltage on the grid is temporarily reduced due to a fault or a load change.

**Table 1: FACTS devices and applications**

| Issue | Device | Comment |
|---|---|---|
| Steady-state voltage control | SVC, SC | Continuous control inherent |
| Dynamic and post-contingency voltage control | SVC<br>STATCOM | Compact design |
| Improvement of steady-state load sharing | SC | Very low losses |
| Transient stability improvement | SC<br>SVC | Inherently self-regulating |
| Power oscillation dampening | SVC<br>TCSC | SVC is location critical while CSC is insensitive to location |
| Power quality improvement | SVC<br>STATCOM | Voltage fluctuation mitigation<br>Flicker mitigation |
| Sub-synchronous resonance mitigation | TCSC | |

Abbreviations: SVC means Static var Compensator; SC means Series Capacitor; STATCOM means Static Synchronous Compensator; TCSC means Thyristor Controlled Series Compensator;
Source: Alberta Department of Energy, "Assessment of Electric Transmission Technologies (2009), pages 23-29

A range of FACTS technologies have been installed in transmission systems in Europe, Asia and the USA. In Alberta, FACTS devices have been approved for use in the Southern Alberta Transmission project.[20] These applications allow for fast control of system voltages that would otherwise not be possible due to variable wind generation.[21] A FACTS in the form of a back-to-back HVDC connection is presently used to provide a non-synchronous connection between the Saskatchewan and Alberta grids.

The major disadvantage of FACTS is the cost. Compared to conventional devices, FACTS are very expensive, which is why despite the long history of development, and its proven track record, FACTS controllers are not widely deployed. A related issue is procurement, for some of the technologies (e.g., SVC) the market is widely developed, whereas for others (e.g., STATCOM) very limited competition exists. Since the devices cost in the order of millions of dollars it is only economically feasible to install a limited number, making optimal placement critical. Therefore, size, appropriate setting and location are additional issues that must be addressed on a case-by-case basis.

[20] Exhibit 123.02, AltaLink Reply Submission, page 11.
[21] Exhibit 123.02, AltaLink Reply Submission, page 11.

### *High Voltage Direct Current (HVDC) transmission technology*

High Voltage Direct Current (HVDC) transmission line technology is expected to improve grid operations[22] and HVDC is considered to be a smart grid technology.[23] HVDC technology and power electronics can provide precise control of power flows on the grid and HVDC lines can carry more power over long distances than a comparable AC link. HVDC transmission lines can transmit more electricity over long distances and experience lower line losses than a comparable AC transmission line. HVDC lines can also be used to connect large AC grids (which may be not be synchronized) and control flows between neighboring power networks.

## Smart grid technologies used in distribution systems

### *Distribution system automation*

Distribution system automation includes: SCADA systems, communication systems for remote data acquisition, distributed field sensors, remote controlled switches such as feeder switches, reclosers and capacitor switches. A variety of advanced distribution management system applications are used to support the operation of the distribution system. Each of these are briefly described below.

Fundamentally there are three functional components of a Distribution Automation (DA)[24] system: control centre applications, data communications infrastructure and technologies, and field equipment and devices.

a. Control centre based control and monitoring system applications include, but are not limited, to the following:

   - Distribution SCADA[25] (Supervisory Control and Data Acquisition) provides real-time monitoring and remote control of switches and devices on distribution circuits from a control centre and may include automatic operation of switches to reconfigure circuits and limit the extent of an outage. Extension of SCADA beyond the substation boundaries can also improve safety for field personnel by providing increased visibility of line and equipment status and conditions.
   - Automated Volt / var Control Systems and Power Quality Management[26] provides monitoring and control of capacitor banks, voltage regulators, and electronic devices to provide improved voltage control and minimize losses, monitor power quality, harmonics, and voltage performance.

[22] Exhibit 103.01, AESO Response to Commission Question 2.
[23] Exhibit 108.02, EDTI Response to Commission Question 2.
[24] Exhibit 91.01, ATCO Electric Response to Commission Question 20.
[25] Exhibit 91.01, ATCO Electric Response to Commission Question 20.
[26] Exhibit 91.01, ATCO Electric Response to Commission Question 20.

- Outage Management Systems (OMS)[27] [28] are software systems that integrate Geographic Information Systems (GIS), Customer Information Systems (CIS) and use customer calls, Automated Metering Reading (AMR) equipment to direct information from network-enabled switches and transformers, and/or SCADA data to predict the outage location and assist in managing outages.
- Advanced Monitoring Systems and Intelligent Applications[29] include systems to integrate information from a variety of different intelligent electronic devices (IEDs) including power quality monitoring systems, relays, reclosers, capacitor controllers, smart switches, etc. These are typically integrated with SCADA and Distribution Automation systems to provide improved system operations, automated fault location and equipment diagnostics.
- Substation Automation (SA)[30] includes substation relays and monitors upgraded to intelligent devices and are connected by direct communication links to enable more advanced digital relay protection, more advanced diagnostics, and safer, more versatile control of apparatuses than is otherwise possible. Digital relays may include monitoring of voltage sags, swells, and interruptions and fault location algorithms.
- Distribution Management Systems (DMS).[31] These systems provide overall integration of multiple distribution management systems and applications including SCADA, substation automation, outage management systems, condition monitoring, load management, voltage/var management and other intelligent applications.
- Enterprise Service Bus (ESB)[32] (sometimes called Enterprise Information Architecture or EIA) connects all smart grid applications within an organization and ensures that the applications are properly and efficiently integrated, with due regard to data standards, integration, conversion, reporting, data retention and supportability. With ESB, applications communicate efficiently because data sharing mechanisms and protocols are fully designed and implemented. Without ESB, multiple point-to-point interfaces between applications are required.
- Conservation Voltage Reduction (CVR)[33] applications are used to reduce peak demand by reducing the supply voltage at appropriate times; for example, when the demand on the distribution system is nearing a maximum, or when supply is highly constrained.[34]
- Fault Detection, Isolation and Restoration (FDIR) applications[35] are used to instantaneously detect both feeder and substation faults and take immediate action, isolate faulted equipment and restore any un-faulted network sections. Fault

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27 Exhibit 91.01, ATCO Electric Response to Commission Question 20.
28 Exhibit 108.02, EDTI Response to Commission Question 20.
29 Exhibit 91.01, ATCO Electric Response to Commission Question 20.
30 Exhibit 108.02, EDTI Response to Commission Question 20.
31 Exhibit 108.02, EDTI Response to Commission Question 20.
32 Exhibit 108.02, EDTI Response to Commission Question 20.
33 Exhibit 108.02, EDTI Response to Commission Question 20.
34 As constant-resistance loads (incandescent lighting, for example) draw power proportional to the square of the supply voltage, system voltage reductions can be used in emergency conditions to reduce peak demand.
35 Exhibit 94.02, General Electric Canada Response to Commission Question 2.

Detection or the initial notification of faults may be initiated via SCADA, monitoring devices or trouble calls.

b. Data communications infrastructures and technologies that acquire and transmit operating data to and from various network points include two-way communication networks that provide connections between every power equipment component and device and transmit data to the utility and system operator, in association with system applications to provide instantaneous/ dynamic information about the distribution system performance.

c. Various field based Distribution Automation (DA) equipment and devices,[36] ranging from Remote Terminal Units (RTU's) to Intelligent Electronic Devices (IED's) are used to measure, monitor, and control the system in real-time. This allows real-time monitoring and remote control of distribution system elements such as substations, transformers, reclosers, protective relays, voltage regulators, distribution lines, capacitor banks, feeder switches, fault analyzers and other physical assets on the distribution system.

[36] Exhibit 110.01, Landis+Gyr Response to Commission Question 20.

# Appendix 7 – Smart metering technologies and related matters

## Appendix 7 – Smart metering technologies and related matters

***This appendix describes the detailed functionality of smart meters, with a focus on specific technologies and standards that currently exist. The appendix discusses some issues relating to meter data management including billing, storage and load settlement in Alberta. The appendix also touches on smart meter technologies that are visible to the end-use consumer such as those that make up the home area network or "HAN".***

### Smart meter functionality[1]

Smart meters are distinguished from traditional meters and automated metering reading (AMR) meters by the presence of:

- two-way communications
- automatic and self-contained interval metering capability

Beyond these basic capabilities, smart meters can include:

- remote connect/disconnect functions
- advanced measurement capabilities
- fraud, tampering and theft detection functions
- equipment for communications into an in-premises network

#### *Two-way communications*

The communications pathway to the meter can be wired or wireless. Several different communications technologies are typically involved in connecting the meter to the utility's enterprise systems. A smart meter might use a wireless radio to communicate to a data aggregation device mounted on a utility pole. The aggregation device could communicate to the distribution entity's back office system using a wired or wireless connection that is independent from the smart meter's network. The utility may use different communication technologies in different parts of their service territory based on physical geography, meter density, building architecture and radio spectrum availability.

#### *Interval metering capability*

Interval metering records energy consumption and demand throughout the day providing support for time-based rates. Typical divisions are 15, 30 or 60 minute intervals. Although the ability for interval metering is technically feasible with the proper combination of AMR and back office systems, AMR is not often used in this manner. Many smart meters have this functionality built

[1] Illinois Statewide Smart Grid Collaborative, "Collaborative Report" (September 30, 2010), page 260, online: Illinois Commerce Commission, http://www.icc.illinois.gov/downloads/public/en/ISSGC%20Collaborative%20Report.pdf.

into the meter itself and the meter can be programmed to submit data to the utility rather than the utility requesting data from the meter.

***Remote connect/disconnect***

Many large utilities in other jurisdictions are choosing to install smart meters with an integrated service switch. Broad deployment of these switches combined with communication technologies will allow the utility to perform both service connect and service disconnect operations remotely, saving on utility personnel trips. Service connections and disconnections are coordinated by the utility's meter management software and are based on utility rules and policies.

***Advanced measurement capabilities***

Power quality is a prevalent topic in the metering industry. The data required to perform power quality calculations are now being specified for residential meters as part of smart grid rollouts. These measurements include voltage, voltage profile, current, and power factor, in addition to energy (kilowatt-hours) and demand (kilowatts). Power quality performance measures such as total harmonic distortion and total demand distortion can be calculated in the meter or in the distribution entity's back office application for use in service assessments and complaint resolution. The Institute of Electrical and Electronics Engineers (IEEE) has standards for power quality characterization and power quality data transmission.[2]

***Fraud, tampering and theft detection***

Meter tampering becomes a greater concern when meter-readers no longer visit the site regularly. Tamper detection and mitigation can be accomplished by several different methods. Some solid-state meters have a hardware tilt detection switch. When the meter is removed from the socket, this hardware switch causes a flag to be set in the meter firmware that is transmitted to the utility the next time the meter is read. When this flag has been triggered several times without a corresponding utility-known reason, this is a clear tampering indication. Other methods for handling tamper detection are available and utilized.

***In-home network communications***

The ability for the smart meter to communicate with a variety of devices within the customer's home is often a major rationale for the deployment of a smart meter system. This network is often referred to as the home area network (HAN) but is not intended to be limited to residential customers as any customer could potentially benefit from the ability to receive information from the smart meter.

The network technology can be wired or wireless depending on the meter vendor. Many smart meters have this capability since it enables applications such as: providing energy usage information to the customer, providing energy price information to the customer, and a variety of

[2] Such as IEEE 519 and the IEEE 1159 series.

demand response programs. A smart meter can communicate data to a variety of devices within the home, including displays, thermostats, pool pumps, appliances, customer owned generation or energy storage and energy management systems. In addition, some applications could entail customer devices providing data to the utility or to a third party, or permit remote control of a customer owned device by the utility or third party. Applications involving customer data or control require policies that protect customer privacy and safety interests.

The smart meter has the capability to communicate usage data to on-site devices and can act as a gateway to the HAN. A smart meter, however, is not the only device available to facilitate this activity. Communication to on-site devices could also be possible using cellular networks, wired phone services, powerline networks or broadband internet connections. There are a number of companies that offer energy monitoring devices directly to consumers either as stand-alone products or bundled with home broadband offerings or security systems.

The communications component of home area networks continues to be in a state of development as competing technologies (wireless and wired) attempt to become the recognized standard to connect end-use devices with the home area network.

While it appears that ZigBee has emerged as the leading wireless standard, it is not considered to be the dominant HAN protocol. A number of alternative communication technologies such as Wi-Fi, ZWave, 6LoWPAN (an acronym for IPv6 over Low power Wireless Personal Area Networks) and HomePlug Powerline, all supported by major industry corporations, are competing for market acceptance and driving product innovation. It is likely that both wireless and wired technologies will be used to connect the multitude of devices to the home area network, especially now that the National Institute of Standards and Technology (NIST), the federal American entity assigned the responsibility for setting smart grid standards, selected the ZigBee (wireless) and HomePlug (wired) Smart Energy standards to be the initial interoperable standard for HAN devices communications and information applications.[3]

HAN can be used with energy management systems to provide the consumer with more control over their electricity usage and electricity bills. Smart meters can work with home energy management systems that include devices such as programmable controllable thermostat, and in-home display devices. On a fully functional basis, home energy management systems are expected to have the capability to integrate data from large appliances, plug-in hybrid electric vehicles (PHEVs), distributed generation (solar panels) and energy storage devices and control the operation of each of these sources or uses of electricity. As PHEVs are introduced into the market, charging stations at work, public locations or even at home will require infrastructure investments. But, with increase penetration of PHEVs, their integration can serve as a resource for electricity planning (residential demand management programs).[4]

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[3] The National Institute of Standards and Technology, "Standards Identified for Inclusion in the Smart Grid Interoperability Standards Framework", online: NIST, http://www.nist.gov/smartgrid/standards.cfm.

[4] K. Doran, F. Barnes & P. Pasrich (eds.), "Smart Grid Deployment in Colorado: Challenges and Opportunities" *University of Colorado at Boulder* (June 2010), page 62, online: Center for Energy & Environmental Security, http://cees.colorado.edu/sgreport.pdf.

## Meter data and relevant regulation

Meters are subject to federal legislation prescribing the units of measurement to be used for electricity billing, along with calibration, verification and inspection requirements.[5] This federal legislation also requires that owners of electricity meters retain certain data relating to a given meter for a period of at least 12 months after the period the meter ceases to be used. The data that must be retained for each meter includes information such as serial numbers and service history, as well as the metering information used by the owner to establish a charge for each billing period.[6]

Load settlement rules in Alberta (discussed in more detail below) also require the retention of metering data for individual meters in order to facilitate adjustments when errors are identified after load has been settled.[7] Current load settlement rules allow for adjustments to occur for a period of up to eight years after the energy was consumed, therefore requiring that this data be accessible for that period.[8]

Participants also noted that Alberta's *Regulated Rate Option Regulation* requires that if an RRO customer is overcharged, the customer must be refunded the amount as soon as practicable after the error is discovered.[9] As this provision does not appear to have a time limitation, some participants have chosen to store metering data into perpetuity in order to facilitate customer bill verification and adjustment. Consequently, if the requirement for hourly meter reads is implemented in conjunction with the installation of smart meters for residential, farm and small commercial customers, the resulting increase in the amount of data that must be stored in order to comply with federal legislation and provincial load settlement requirements must be considered when assessing total costs.

Ontario implemented smart meters as a result of government legislation (see Appendix 4 – Status of smart grid deployment in other jurisdictions) and recognized the need for a central data repository due to its market design. The Ontario Independent Electricity System Operator was first asked in 2006 to assist with the procurement of a system to provide a centralized meter data manager/repository and subsequently to oversee its implementation and operation. Consequently, the Smart Metering Entity was created by statute, and the Independent Electricity System Operator was designated as that entity.[10]

The Smart Metering Entity has the exclusive authority to carry out the following functions: (i) receiving smart metering data for the purpose of carrying out the functions defined in regulation, including receiving other information necessary for those functions; (ii) providing all services, as specified by the Smart Metering Entity, performed on smart metering data to produce

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5 For example, *Electricity and Gas Inspection Act*, R.S.C. 1985, c. E-4.
6 *Electricity and Gas Inspection Regulations*, SOR/86-131, Section 11(2).
7 AUC Rule 021: *Settlement System Code Rules*.
8 AUC Rule 021, Section 5.3 (Post-Final Adjustment Mechanism).
9 Exhibit 198.01, FortisAlberta Response to Commission Questions to Distribution Companies, page 6.
10 *Electricity Act*, S.O 1998, c.15, Part IV.2; also, Ontario Reg. 393/07, as amended by O. Reg. 233/08.

billing quantity) data, including validation, estimating and editing services; (iii) managing access rights to smart metering data and data derived from smart metering data in a manner consistent with the objects of the Smart Metering Entity; and (iv) maintaining and operating a database of smart metering data and other data that is necessary for the Smart Metering Entity to perform the exclusive functions defined in regulation, and data that is derived through the exclusive functions.[11]

Local distribution companies in Ontario have the authority to collect and access the data that is stored by the Smart Metering Entity.

## Load settlement in Alberta

Generators sell their electrical energy into the power pool, where the pool price is established every hour. Each generator is paid for the electrical energy produced every hour. Electricity retailers buy electrical energy from the power pool at the hourly pool price and sell electrical energy to the consumers.

The AESO is responsible for carrying out financial settlement for all electric energy exchanged through the power pool at the pool price. Because the wholesale pool price varies on an hourly basis, the AESO must bill retailers for their customers' electricity consumption according to the hour it was used.

Electricity retailers bill for electrical energy consumed by their customers but do not physically deliver the electricity to their customers; electricity distributors do. Electricity distributors accept electricity from the transmission system at various points of delivery (PODs) which is then delivered through the distribution system to homes and businesses.

The distributor also performs the function of calculating and reporting to the power pool how much electrical energy was allocated to each retailer in each hour of every day. This function is called load settlement, and when the distributor performs this function it is acting as the load settlement agent.

At the PODs, the distributors have meters that measure the electricity by the hour (interval meter). Residential, farm and small commercial customers usually have meters that measure how much electricity was used in total since the last time the meters were read (cumulative meters). Cumulative meters are typically read once a month. Consequently, the distributor will only know the total amount of electrical energy consumed by a customer in that month. The load settlement agent is required to allocate that monthly total into the 720 hours in a given month. Load settlement agents typically use profiles to split the total usage into hourly amounts. Sometimes the profiles are based on typical consumption patterns of similar customers; in other cases profiles are based on what the PODs are measuring.

[11] Ontario Reg. 233/08, Section 5; also, Exhibit 187.01, IESO Correspondence, letter dated October 4, 2010.

Because the hourly amounts allocated by profiles are approximations only, the total of all of the hourly amounts, plus the estimated distribution line losses, will never equal the POD hourly measurements. The difference is called Unaccounted for Energy (UFE). UFE is calculated and converted to a percentage that is then applied to the profiled consumption of each customer with a cumulative meter and to the measured consumption of each customer with an interval meter.

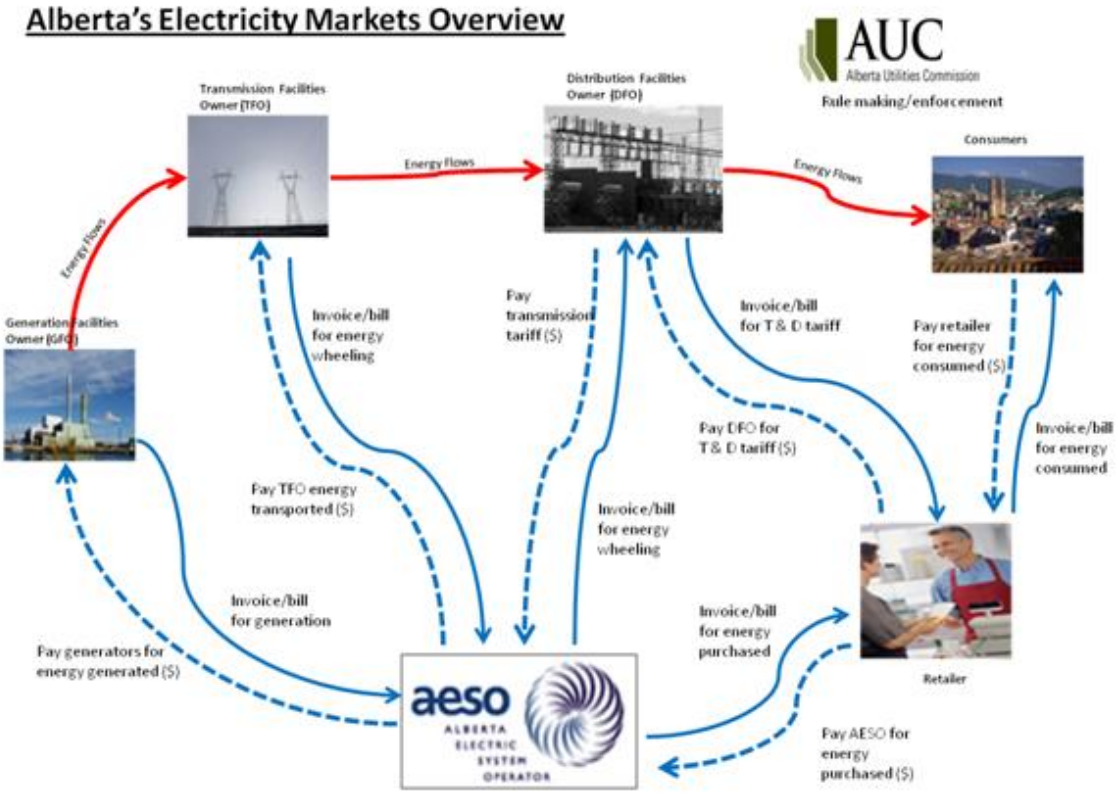
Load settlement agents gather the meter data, profile it, calculate the distribution line losses, compare the totals to the POD measurements and then determine UFE and allocate that UFE to all customers, and they perform those steps for each hour. At the end, the load settlement agent has the information by hour by customer to provide to the AESO, so that the AESO can determine how much electricity each retailer is responsible for paying for in each hour.

If all households and small commercial sites had interval meters, the steps performed by the load settlement agents would change slightly, but all of the steps would still be performed. Instead of profiling the usage of the majority of consumers of electricity, profiling would still be required but only for those cases where there is no meter (e.g., traffic lights and streetlights).

Instead of collecting monthly reads from households, the hourly meter data collected from the hourly meters would need to go through a process of validation and estimation for those hours where there is missing data or improbable reads. Once all of the hourly meter reads are validated and missing or improbable ones are estimated, the load settlement agent would then go through the other settlement processes of determining distribution line losses and UFE.

Hourly reads from interval meters would result in a 720-fold increase in the number of residential and small commercial meter reads exchanged by the various market participants. A retailer with 100,000 customers would previously have received 1.2 million meter reads a year for billing purposes; with hourly meter reads that same retailer would receive 864 million meter reads. Because the retailers use meter reads to invoice their customers, the retailers would likely need to keep copies of those meter reads for audit purposes. Market participants (AESO, LSAs, distribution entities, retailers) would likely be required to keep copies of this additional meter data in order to comply with federal legislation or provincial load settlement requirements discussed above.

**Figure 1: Alberta's electricity market overview**



# Appendix 8 – List of participants in the Inquiry

## Appendix 8 – List of participants in the Inquiry

1. ABB Inc.
2. Alberta Party Edmonton-Centre Constituency Association
3. Alberta Direct Connect Consumer Association
4. Alberta Electric System Operator
5. Alberta Federation of Rural Electrification Associations Ltd.
6. Alberta Municipal Power Systems
7. Alberta Urban Municipalities Association
8. Alcatel-Lucent Canada
9. AltaGas Utilities Inc.
10. AltaLink Management Ltd.
11. Jim Anderson
12. ARC Business Solutions Inc.
13. ATCO Electric Ltd.
14. The City Of Calgary
15. Carbon Busters Inc.
16. Central Alberta Rural Electrification Association[1]
17. Citizens Advocating the Use of Sustainable Energy
18. Consumers Coalition of Alberta
19. Cisco Systems Canada Co.
20. Cognera Corp.
21. Corix Utilities Inc.
22. Rick Cowburn

[1] Participated jointly with the South Alta Rural Electrification Association.

23. Direct Energy Marketing Limited
24. ENMAX Corporation
25. EPCOR Distribution & Transmission Inc.
26. European Power Systems Ltd.
27. FortisAlberta Inc.
28. General Electric Canada (GE Energy)
29. Hansen Comprehensive Regional Land Use Planning
30. Honeywell Utility Solutions
31. IBM Canada Ltd.
32. Inter Pipeline Fund
33. Industrial Power Consumers Association of Alberta
34. Independent Power Producers' Society of Alberta
35. Just Energy Alberta L.P.
36. Duncan Kinney
37. Dalibor Kladar
38. Landis + Gyr Canada
39. Lavesta Area Group
40. City of Lethbridge[2]
41. Medicine River Valley Landowners Group
42. Dr. C. P. V. Nostrand
43. Office of the Information and Privacy Commissioner of Alberta
44. Oldman 2 Wind Farm Ltd.
45. The Pembina Institute for Appropriate Development

[2] Participated jointly with The City of Red Deer.

46. Plutonic Power Corporation
47. The City Of Red Deer[3]
48. Responsible Electricity Transmission for Albertans
49. South Alta Rural Electrification Association[4]
50. Sierra Club Prairie
51. Smart Synch, Inc.
52. Suncor Energy Inc.
53. TELUS Communications Company
54. TransAlta Corporation
55. TransCanada Energy Ltd.
56. Office of the Utilities Consumer Advocate
57. Utility Network & Partners Inc.
58. Bruce Winter

[3] Participated jointly with the City of Lethbridge.
[4] Participated jointly with the Central Alberta Rural Electrification Association.

# Appendix 9 – Glossary and abbreviations

## Appendix 9 – Glossary and abbreviations

| **Glossary** |
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| Advanced Metering Infrastructure: Technology, including metering technology and network communications and information technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. |
| Alberta Electric System Operator**:** The non-for-profit corporation established by subsection 7(1) of the *Electric Utilities Act* charged with the operation and economic planning of the Alberta Interconnected Electric System. |
| Alberta Interconnected Electric System: The system of interconnected transmission power lines and generators in Alberta. |
| Alberta Municipal Power Systems: An alliance of municipally-owned and operated electric distribution system whose membership includes the Towns of Cardston, Fort Macleod and Ponoka and the Municipality of Crowsnest Pass. |
| Ancillary services: Services necessary to support the transmission of energy from generating resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice. |
| Automatic meter reading: A system to read aggregated usage electronically. Examples include handheld readers, drive-by reader and other read-only devices used to capture a simple aggregated monthly billing read. |
| Base-load capacity/generation: The generating equipment normally operated to serve loads on an around-the-clock basis. |
| Black start: The process of restoring a power station to operation without relying on external energy sources. |
| Bulk transmission system: The integrated system of transmission lines and substations that delivers electric power from major generating stations to load centres. The bulk system, which generally includes 500-kilovolt (kV) and 240-kV transmission lines and substations, also delivers/receives power to and from adjacent control areas. |
| Capacity: The maximum sustainable amount of electrical energy that can be produced or carried at an instant. |
| Cogeneration: The simultaneous production of electricity and another form of useful thermal energy used for industrial, commercial, heating or cooling purposes. |
| Customer Average Interruption Duration Index: The average time needed to restore service to the average customer per sustained interruption. It is the sum of customer interruption durations divided by the total number of customer interruptions. |

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| Demand response: Changes in electrical energy usage by customers in response to incentive payments designed to induce lower electricity use at times of high power pool prices or when system reliability is jeopardized. |
| Demand: The volume of electric energy delivered to or by a system, part of a system, or piece of equipment at a given instant or averaged over any designated period of time. |
| Demand-side management: Activities that occur on the demand (customer) side of the meter and are implemented by the customer directly or by load serving entities. |
| Direct current: Current that flows continuously in the same direction (as opposed to AC). The current supplied from a battery is direct current. |
| Dispatch: The process by which a system operator directs the real-time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to, or taken off, the system. |
| Distributed generation: Small-scale power sources typically connected to a distribution system at customer locations. |
| Distribution automation system: A system that enables an electric distribution utility to remotely monitor, coordinate and operate distribution components, in a real-time mode from remote locations. |
| Distribution system: The portion of an electric system that is dedicated to delivering electric energy from the transmission system to an end-use customer. |
| Distribution utility: A regulated electric utility entity that constructs and maintains the distribution wires connecting the transmission grid to an end-use customer. Also referred to as distribution entity or owner of distribution system |
| Federal Energy Regulatory Commission: The independent agency that regulates the interstate transmission of electricity, natural gas, and oil. It also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. |
| Generating plant: A facility housing one or more generating units. |
| Generating unit: Any combination of an electrical generator physically connected to reactor(s), boiler(s), combustion or wind turbine(s) or other prime mover(s) and operated together to produce electric power. |
| Gigawatt hour: One billion watt hours. |
| Gigawatt: One billion watts. |
| Grid: A system of interconnected power lines and generators that is operated as a unified whole to supply customers at various locations. Also known as a transmission system. |

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| High voltage direct current: The transmission of electricity using direct current. |
| Independent System Operator: A system and market operator that is independent of other market interests. In Alberta the entity that fulfils this role is the Alberta Electric System Operator. |
| Inquiry: The Alberta Smart Grid Inquiry conducted by the Alberta Utilities Commission. |
| Interconnection or transmission interconnection: An arrangement of electrical lines and/or transformers that provides an interconnection to the transmission system for a generator or large commercial or industrial customer. |
| Intertie: A transmission facility or facilities, usually transmission lines that interconnect two neighbouring transmission systems. |
| Kilovolt-ampere: A common unit of apparent power, which is 1,000 volt-amperes. The volt-amperes carried or used by an electrical device are the mathematical products of the volts and amperes of the device. |
| Kilowatt hour: One thousand watt hours; a measure of electric energy. |
| Kilowatt: One thousand watts; a measure of electric demand. |
| Load factor: The ratio of average power demand (load) over a stipulated period of time to the peak or maximum for that same time interval; sometimes expressed as a per cent. |
| Load: The electric power used by devices connected to an electric system. |
| Megawatt: One million watts. |
| Megawatt-hour: One million watt hours. |
| Merit order: In the electricity wholesale market, merit order refers to the list used to dispatch electric generation to meet demand. The lowest cost generation is dispatched first. |
| Meters or metering: Equipment that measures and registers the amount and direction of electrical quantities. |
| Micro-generation: In Alberta, micro-generation is defined as being from 150 kW to one MW of exclusively renewable or alternative energy that is intended to meet all or a portion of the customer's electricity needs. |
| Micro-grids: Small networks of generating sources capable of operating independently from the electricity system. |
| Non-coincidental peak load: The sum of two or more peak loads on individual systems, or a portion of a system, that do not occur in the same time interval. |

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| North American Electric Reliability Corporation: The international independent, self-regulatory, not-for-profit organization whose mission is to ensure the reliability of the bulk power system in North America. It is subject to oversight by the Federal Energy Regulatory Commission and Canadian governmental authorities and was certified by the Federal Energy Regulatory Commission as the electric reliability organization for the U.S. on July 20, 2006. |
| Off-peak: Periods of the day, season, year or other defined timeframe when loads are less than the maximum for the timeframe specified. |
| On-peak: Periods of the day, season, year or other defined timeframe when loads are at a maximum level for the timeframe specified. |
| Operating reserve: Generating capacity that is held in reserve for system operations and can be brought online within a short period of time to respond to a contingency. Operating reserve may be provided by generation that is already online (synchronized) and loaded to less than its maximum output and is available to serve customer demand almost immediately. Operating reserve may also be provided by interruptible load. |
| Peak load/demand: The maximum power demand (load) registered by a customer or a group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or, more usually, the average load over a designated interval of time such as one hour, and is normally stated in kilowatts or megawatts. |
| Peaking capacity: Generation capacity that is normally used to produce electricity during peak-load hours. |
| Phasor measurement unit: A device which reports the magnitude and phase angle of an analog and /or derived phasor with respect to the global time reference, as per the synchrophasor standards. It is used to measure voltages and currents. |
| Point-of-delivery: Point(s) for interconnection on the transmission facility owner's system where capacity and/or energy is made available to the end-use customer. |
| Power pool: An independent, central, open-access entity that functions as a spot market, matching demand for electrical energy with the lowest-cost supply of electrical energy to establish an hourly pool price. |
| Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities. |
| Rural electrification association: A not-for-profit cooperative incorporated or continued under the Rural Utilities Act, which owns an electric distribution system and supplies electric energy to members in a rural region of Alberta. |

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| Simple cycle gas turbine: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases are passed to the turbine where they expand; driving the turbine that in turn drives the generator. |
| Static var compensator: An electrical device for providing fast-acting reactive power compensation on electricity networks. |
| Substation/switching station: A facility where equipment is used to tie together two or more electric circuits through switches (circuit breakers). The switches are selectively arranged to permit a circuit to be disconnected or to change the electric connection between the circuits. |
| Substation: A subsidiary station of an electrical generation, transmission and distribution system where voltage is transformed from high to low, or the reverse. Electric power may flow through several substations between generating plant and consumer, and may be changed in voltage in several steps. |
| Switchable system: A system of power lines in which circuits are contiguously connected between substations and then back to the same substation. |
| System Average Interruption Duration Index: The total average time that customers on a distribution system are interrupted. It is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information as to the average time the customers are interrupted. It is the sum of the restoration time for each interruption event times the number of interrupted customers for each interruption event divided by the total number of customers. |
| System Average Interruption Frequency Index: The average frequency of sustained interruptions per customer over a predefined area. It is the total number of customer interruptions divided by the total number of customers served. |
| Transformer: An electrical device for changing the voltage of alternating current. |
| Transmission Facility Owner: The owner of the system of high voltage power lines and equipment that links generating units to large customer loads and to distribution systems. |
| Transmission losses: Energy that is lost through the process of transmitting electrical energy. |
| Transmission system: An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers or is delivered to other electric systems. |
| Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer. |

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| Variable generation: The output of wind, solar, ocean and some hydro generation resources varies according to the availability of the primary fuel (wind, sunlight and moving water) that cannot be reasonably stored. Therefore, these resources are considered variable, following the availability of their primary fuel source. |
| Voltage: The difference of electrical potential between two points of an electrical circuit expressed in volts. It is the measurement of the potential for an electric field to cause an electric current in an electrical conductor. Depending on the amount of difference of electrical potential, it is referred to as extra low voltage, low voltage, high voltage or extra high voltage. |
| Watt hour: An electrical energy unit of measure equal to one watt of power supplied to or taken from an electric circuit steadily for one hour. |
| Watt: The unit of power equal to one joule of energy per second. It measures a rate of energy conversion. A typical household incandescent light bulb uses electrical energy at a rate of 25 to 100 watts. |
| Western Electricity Coordinating Council: The organization formed to coordinate and promote electric system reliability for the system that interconnects Alberta, B.C., 14 western U.S. states and part of one Mexican state. |

| **Abbreviation** | **Name in full** |
|---|---|
| AC | alternating current |
| AESO | Alberta Electric System Operator |
| AFREA | Alberta Federation of Rural Electrification Associations |
| AIES | Alberta Interconnected Electric System |
| AMI | advanced metering infrastructure |
| AMPS | Alberta Municipal Power Systems |
| AMR | automatic meter reading |
| AUC or the Commission | The Alberta Utilities Commission |
| CAIDI | customer average interruption duration index |
| CAREA | Central Alberta Rural Electrification Association |
| DAS | distribution automation system |
| DC | direct current |
| DSM | demand side management |
| DTLR | dynamic thermal line ratings |
| FACTS | flexible AC transmission |
| FERC | Federal Energy Regulatory Commission |
| GW | gigawatt |
| GWh | gigawatt hour |
| HAN | home area network |
| HVDC | high voltage direct current |
| IEC | International Electrotechnical Commission |
| ISO | Independent System Operator |
| kVA | kilovolt ampere |
| KW | kilowatt |
| KWh | kilowatt hour |
| LCD | liquid crystal display |
| LED | light emitting diode |
| MW | megawatt |
| MWh | megawatt hour |
| NERC | North American Electric Reliability Corporation |
| NIST | National Institute of Standards and Technology |
| PHEV | plug-in hybrid electric vehicle |
| PMU | phasor measurement unit |

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|---|---|
| POD | point-of-delivery |
| REA | Rural Electrification Association |
| RRO | Regulated Rate Option |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| SAREA | South Alta Rural Electrification Association |
| SCADA | supervisory control and data acquisition |
| SVC | static var compensator |
| TFO | Transmission Facility Operator |
| UCA | the Office of the Utilities Consumer Advocate |
| UFE | unaccounted for energy |
| var | volt ampere reactive |
| WECC | Western Electricity Coordinating Council |

# Appendix 10 – Alberta Utilities Commission Panel, Consultants and Staff

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Smart Grid Inquiry Panel

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