



Market & Operational Framework For Wind Integration In Alberta

September 26, 2007

1. INTRODUCTION

Around the world the interest in, and development of, wind power continues to grow. Global installed wind energy capacity has increased from approximately 18,000 MW in 2000 to 59,000 MW in 2005.¹ Alberta has adopted a leadership position in wind power development in Canada, being the first jurisdiction to develop wind interconnection standards and currently leading in wind penetration with 497MW of wind generation and much more in development. Large-scale integration of wind power, however, is still relatively new and presents new operational opportunities and challenges. The AESO recognized that it was important, both to system reliability and to the successful development of renewable resources in Alberta, that the impact on power system operations was understood as Alberta reached new levels of wind penetration. The development of the Market & Operational Framework published on March 8, 2007 and subsequent consultation on the framework has provided both stakeholders and the AESO with additional clarity.

This paper establishes the Market and Operational Framework for Wind Integration and defines the mitigation measures the AESO will use to manage variability as well as the order of use and cost responsibility. The framework will guide the AESO and stakeholders and form the foundation for work required to further refine and define rules, tools and procedures needed to integrate as much wind power into the Alberta system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.

2. BACKGROUND

Reliable power system operation requires precise balancing of supply and demand in accordance with minimum operating criteria. The AESO system controller manages supply-demand balance on a minute to minute basis considering load forecasts, operating uncertainties (i.e. unit de-rates and outages) and using current resources, rules and procedures.

As a power source, wind power holds great potential for Alberta. It is clean, renewable and Alberta contains a range of suitable wind generation sites. However, wind power has a number of attributes that make managing the reliability of the system significantly more challenging than managing the existing, predominately thermal generation. These include:

- potential for extremely fast ramps (increases or decreases)
- unpredictable wind (fuel source uncertainty)
- output variability and
- production uncorrelated with load

The operational impacts resulting from the wind power may appear across all time frames, from seconds to minutes to hours. The current size and portfolio of Alberta's electricity market (predominantly thermal and a large amount of cogeneration) and its limited interconnection capability limits Alberta's ability to 'share' or dampen the wind power variability in the near term. This will affect the current resources and practices used to maintain supply-demand balance, magnifying the amount and responsiveness of resources needed.

In 2004, the AESO began working with stakeholders, wind developers and other jurisdictions to better understand the impact of integrating wind power into the Alberta Interconnected Electric System. Subsequently, the November 2005 Phase I Study² and the April 2006 Phase II Study³ were conducted with industry collaboration. The studies indicated wind power poses system

reliability concerns as wind penetration increases in the absence of corresponding mitigation measures such as increased regulating reserves, wind forecasting and power management of wind resources. In addition, it was noted that the scope, scale and potential cost of mitigating measures escalated rapidly as wind penetration increased beyond about 900 MW.

Facing substantial wind additions in the near term, the AESO established a temporary 900 MW threshold to ensure continued system reliability until appropriate mitigation measures could be defined and associated cost allocations determined. The AESO continues to work with Alberta industry stakeholders and system/market operators in other jurisdictions to implement the Market and Operational Framework including further defining the rules, tools and procedures the AESO will employ to integrate increasing volumes of wind power into the Alberta system without compromising system reliability or the fair, efficient and openly competitive operation of the market.

3. MARKET and OPERATIONAL FRAMEWORK

Alberta's energy-only market structure is essentially an imbalance market – the structure is intended to accommodate variability of both demand and supply. In today's predominantly thermal generation environment, the AESO system operators effectively manage 1500 MW daily load cycles and other operating uncertainties with its current resources, rules and operating procedures. The supply uncertainty that will accompany higher wind penetration will require enhanced resource responsiveness and new policies and procedures in order to maintain supply-demand balance. The Market and Operational Framework will enable additional wind energy to be integrated into the AIES without compromising system reliability or the fair, efficient and openly competitive operation of the market.

3.1 Description of Mitigating Tools

The basic premise of the Market and Operational Framework for adding wind power to the AIES is as follows:

If the System Operator receives a reasonable forecast of wind power generation, then the System Operator can establish operating plans to accommodate the forecast wind energy by using the following tools:

- The Energy Market Merit Order (EMMO)
- Regulating Reserves
- Load / Supply Following Services
- Wind Power Management

Geographic diversity of the wind generation resources will tend to reduce the need to use these tools, or conversely increase the amount of wind generation that the AIES will be able to absorb.

The Market and Operational Framework strikes a balance between ensuring system reliability and maintaining a fair, efficient and openly competitive market.

3.1.1 Wind Power Forecasting

The nature of wind speed – its uncertainty and potential for rapid rates of change – means that wind power is also uncertain and liable to rapid rates of change. This creates opportunities and challenges in managing the reliability of the system. The AESO's own studies, as well as studies conducted in other jurisdictions, have shown that increased accuracy in forecasting wind speeds and the resulting wind power can reduce operational wind integration issues. It can also lessen the need for, and cost of, other mitigating measures. As such, wind forecasting is expected to be an important tool for managing the variable nature of wind power and key to reliably increasing wind penetration.

Wind power forecasting will not eliminate the need for other mitigating measures. Rather, to the extent that forecasting improves predictability, it will reduce the need for, and use of, other operational tools. The AESO is undertaking a Wind Forecasting Pilot Project comparing the effectiveness of different wind forecasting methodologies across Alberta and over different time horizons. This project will provide important insights regarding forecasting methods, utilization of forecasts, and the degree of mitigation achievable. This will, in turn, help establish forecasting capability standards for wind generators which will form part of their interconnection and operating requirements.

It is envisioned that all wind power facilities will forecast their power output (or provide the data necessary for centralized forecasting) for next day as well as two hours prior to the start of the delivery hour, and possibly other timeframes determined to be useful and reasonable. The system controller will then incorporate the forecast into the operational plan to maintain supply and demand balance on the AIES while accommodating the expected output from the wind generators. This will help mitigate wind power variability by improving the accuracy and efficiency of planning and procuring the regulating reserves and load/supply following services discussed below.

3.1.2 Energy Market Merit Order (EMMO)

As mentioned previously, the energy-only market structure is an imbalance market that accommodates variability of both demand and supply. One of the duties of the ISO, as defined by the EUA, is "to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta..."⁴

The Energy Market Merit Order (EMMO) is the primary mechanism by which the relative economic merit of supply offers are evaluated and dispatched to meet load requirements. With implementation of the Must Offer Must Comply rules, offers contained within the EMMO are price and volume certain two hours prior to the start of the delivery hour, which is referred to as T-2. At T-2, the ramping capability of the EMMO is also known. The EMMO can be dispatched by the system operator as often as is necessary in combination with the regulating reserves described below to maintain supply demand balance on the AIES.

Wind is not fully dispatchable. As a result, suppliers of wind power will not offer their supply into the market or be able to set price. The wind forecast will establish energy schedules priced at \$0 and wind suppliers will be 'price takers'.

3.1.3 Regulating Reserves

Regulating Reserves are fast responding resources that are used in real time to help maintain supply demand balance typically within the 20 minute timeframe. They are controlled directly by the AESO Automatic Generation Control (AGC) System. Regulating Reserves are fast responding and, at a minimum, must be capable of ramping through the regulation range within 10 minutes to be a qualified resource. (For complete details on the technical requirements for Regulating Reserves please refer to www.aeso.ca/files/Tech-req-req-res-vs_2.0_final.pdf.)

The AESO Phase II Study found that Regulating Reserves are "... an effective measure in mitigating the effects of short term wind power variability"⁵ within 20 minutes. Similarly, variability analysis conducted in Phase I indicated intra-20 minute variability of net demand (wind plus load variability) only increased marginally with increasing wind penetration suggesting that it could be reasonably managed with existing or relatively small increases in regulating reserves. It is envisioned that the AESO will plan for and procure sufficient regulating reserves to manage intra-20 minute variability that is expected based on forecasts and established forecasting accuracy standards (set in interconnection standards and agreements).

The AESO will continue to procure regulating reserves in order to manage forecasted variability in the supply demand balance to the extent qualified resources are offered and available in the Operating Reserves market.

3.1.4 Load/Supply Following Services

The larger or more critical reliability risk associated with wind power is wind ramping that persists from 20 minutes to hours particularly when wind ramps in the opposite direction of the system load. In other words, the wind picks up as electricity usage is decreasing or vice versa. The Phase II Study concluded that Regulating Reserves "can assist in managing the longer term wind power ramps"⁶ but that the amount needed would increase as wind penetration increases. Depending on wind penetration levels, wind ramping could be managed with additional regulating reserves, a new load/supply following service or both.

Load/supply following is similar to regulating reserves, except that it is a slower service used to respond to changes in wind ramping that last 20 minute to several hours. This less stringent ramping requirement should widen the potential for suppliers along with available resources such as storage facilities, inter-control area dynamic schedules, load shedding services and others.

Procurement of load/supply following would be based on wind forecasts and established forecasting accuracy standards that will be set in interconnection standards and agreements. The procurement of regulating reserves versus load/supply following would be based on the proportion of intra-20 minute variability to ramping deviations expected.

Use or dispatch of regulating reserves versus load/supply following would depend on which would best meet technical operating or reliability requirements in the most efficient (cost effective) manner within established market rules. Rules, procedures and system tools will need to be developed to achieve the necessary optimization and ensure effective and transparent decision making.

Regulating reserves and load/supply following services will not always be adequate to balance supply with demand. In these cases, wind power management techniques will need to be employed.

3.1.5 Wind Generator Power Management

ISO Rule 6.7 requires the system controller to “issue directives to market participants as required to prevent a threat to system security or to return the AIES to a safe and reliable state”⁷ and requires market participants to “use reasonable efforts to comply with directives from the system controller to prevent a threat to system security or to assist in the recovery from or return the AIES to a safe and reliable state.”⁸

In situations where the system cannot absorb all the forecasted or actual wind power generated, maintaining system security will call for wind power to be dispatched down, ramp rate limited or dispatched off. To do this, wind power facilities will be required to have power management capabilities, including Power Limiting and/or Ramp Rate Limiting. Power Limiting is the capability to limit power at the facility to a specified level while Ramp Rate Limiting is the capability to control the rate at which wind power increases or decreases. Both are designed to control real time wind production levels. The Phase 2 study concluded that Power Limiting was more effective and resulted in less overall lost production of wind generation.⁹ Therefore, Power Management, in the form of Curtailment, Power Limiting or Ramp Rate Limiting, will be exercised when EMMO, regulating reserves and load/supply following do not enable the system to absorb all of the forecasted or actual wind generation.

In general, wind generators may face risk of power management due to insufficient resources to accommodate either the actual or forecasted wind generation. This may occur during the following conditions:

- a. Forecast loss of wind and insufficient ancillary services or ramping services
- b. Supply surplus conditions (out of market \$ 0 offer dispatch) – thermal units will not be dispatched below the minimum stable operating limits
- c. Insufficient ancillary services due to market conditions or emergency conditions (e.g. SCADA failure)
- d. Unforeseen (i.e. not forecasted) wind conditions such as a microburst
- e. Disturbance and emergency conditions – wind may be dispatched off during islanding conditions or system emergencies where wind variability cannot be tolerated

The actual duty, frequency and magnitude of power management will depend on a number of factors including; actual wind penetration and production, wind diversity, forecasting accuracies, system response and supply portfolio and offer (price) strategies. The AESO expects that over time through operating experience, these approaches will be refined and improved.

Technical requirements for power management will be defined and applicable to the November 2004 “Wind Power Facility Technical Requirements.” All entities that entered into interconnection agreements on that basis, or based on subsequent technical requirements, will be subject to these requirements. Further consideration will be needed to determine if facilities constructed under earlier interconnection agreements and standards should be grandfathered and exempt from these requirements or whether other suitable arrangements can/should be put in place.

3.1.6 Wind Power Diversification

Wind can vary considerably across Alberta. For example, when the wind is blowing in Lethbridge, it may not be blowing in Lloydminster. So as some wind facilities are ramping up, others are ramping down. In this way, distributing wind power facilities geographically can help reduce aggregate wind power variability and ramping impact on the system. The AESO Phase 1 Study¹⁰ found that “in the 20-minute and less time frame, wind power variability increases with wind power development, but not in proportion to the wind power development.” More recently, the Ontario Wind Integration Study reported that diversity “would tend to limit the impact of individual site or group changes on the aggregate wind output”¹¹ and concluded that this diversity dampened variability on the system over time.¹²

The wholesale electricity market contemplated by the Electric Utilities Act (EUA) requires a “flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces....”¹³ The ISO expressly does not have a role in the centralized planning of generation investments. As such, the final arbiter of the value of wind power diversification will be the investors that allocate capital to specific wind generation facilities.

3.2 Cost Allocation

Each of the tools discussed above has an associated cost. The Market and Operational Framework developed by the AESO proposes the following cost allocations. The basis of the cost allocation is included in Section 3 – Consistency with Overall Market Policy.

- **Forecasting:** The ongoing cost of providing wind forecasts (or data necessary for centralized forecasting) that meet AESO standards will be allocated to individual wind power facilities. Costs necessary for the AESO to produce aggregated wind forecasts and/or integrate wind forecasts into operational processes and tools will most likely be recovered through the AESO tariff/fees.
- **Regulating Reserves & Load/Supply Following:** The AESO will procure regulating reserves and load/supply following services to the extent necessary for the wind forecasts and an acceptable level of forecasting error and costs associated with increased ancillary services will be allocated to load.
- **Power Management:** Costs associated with wind power management, both capital (equipment) and opportunity (lost production due to power management), will be borne by the wind generators.

As mentioned previously, in a deregulated, competitive, electricity market, such as in Alberta, investment decisions regarding the type and location of generation assets are driven by market forces. Decisions regarding generating facilities reside with market participants along with those associated costs. As such, the final arbiter of the value of wind power diversification will be the investors that allocate capital to specific wind generation facilities.

4. CONSISTENCY WITH OVERALL MARKET POLICY

The Market and Operational Framework is intended to ensure system reliability as well as maintain a fair and openly competitive electricity market. It is consistent with the overall Market Policy and the obligations of other forms of supply assets connected to the AIES.

4.1 Context – Setting References from Related Documents

The wholesale electricity market contemplated by the EUA requires a “flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces....”¹⁴

The EUA clearly establishes the duty of the ISO to “provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity”¹⁵ and to “facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so....”¹⁶

The ADOE has provided additional clarity as follows:

“The Department does not support one type of generation over another but rather allows competitive market forces to determine the appropriate generation mix (e.g. no fuel use policy). As a result, the Department does not support market refinements that will create an uneven playing field or be detrimental to the development of renewable resources.”¹⁷

The ADOE has also asserted the following:

“Environmentally friendly power generation benefits all customers with a cleaner environment and reduction in environment-related health problems. It also assists Alberta in meeting environmental emission targets under Clean Air Strategic Alliance (CASA).”¹⁸

Alberta’s Electric Policy Framework (the “Policy Framework”) also makes the following assertion with respect to wind generation and reliability:

“The variability of wind generation may create reliability concerns for the system operator, particularly as the amount of wind generation exceeds a certain threshold. The challenges include, control strategies, interconnection standards, volume/forecasting and potential system reliability impacts (e.g. RUC uncertainty and increased need for additional capacity and/or operating reserves). It is important that market rules are appropriate and obligations and responsibilities are defined for all types of generation without creating burdensome or detrimental requirements.”¹⁹

The Policy Framework recognizes that the “variability and non-dispatchable nature of wind presents challenges to system operators and market design”²⁰ and requires that the “attributes of wind generation technology must be considered while maintaining fairness to all market participants.”²¹

The Policy Framework also stipulates that the ISO “will make rules to ensure that wind and other intermittent resources are able to participate fairly in the energy market. The rules will consider characteristics of wind generation so that wind may be properly accounted for in any reliability assessment”²²

4.2 Wind Power Forecasting versus “Must Offer”

The Policy Framework recognizes that “design of competitive markets for electricity requires a balance between the needs of the market and system reliability requirements...”²³ and that the “system operator does not always know if there will be enough generation available in the supply stack to meet the load...because there is no certainty of available capacity from day-ahead schedules, there is no market mechanism to commit additional units on a day-ahead basis and”²⁴

A key recommendation of the Policy Framework is the establishment of a “must offer/must comply” obligation as follows:

“The Department recommends that market participants with supply must submit their energy price quantity pairs for the energy market before gate closure on the day before the delivery day. All available volume must be offered and the total volume may not be restated except for physical operational reasons. In addition, dispatch issued by the ISO must be complied with. “Any change or limitations to availability must be immediately communicated to the ISO. Unexpected volumes from a unit that comes back from an outage early would be allowed into the market.”²⁵

The unique attributes of wind generation makes “must offer” difficult, if not impossible for wind generators. The obligation that all generators must communicate any change or limitation to availability to the ISO supports a “must forecast” obligation (or provide the data necessary for centralized forecasting) for wind generators and that the ongoing costs associated with that obligation are allocated to wind generators.

4.3 Regulating Reserves, Load/Supply Following and Ancillary Services

The Electric Utilities Act defines ‘Ancillary Services’ as “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.”²⁶ It also stipulates that the ISO has the duty “to manage and recover the costs for the provision of ancillary services”²⁷ By the definition contained in the EUA, both, Regulating Reserves and the contemplated Load/Supply Following Services, are “ancillary services.”

The responsibility for transmission costs are clearly established by the Transmission Development Policy as follows:

“Generator Cost Responsibility

In general, generators will be responsible to pay for several elements of transmission including:

- a. Local interconnection charges
- b. Location-based loss charges, and
- c. A financial commitment and payment towards transmission system upgrades

The balance of remaining transmission costs (i.e. wires, TMR, IBOC/LBCSO, operating reserves, etc.) will be allocated to load.”²⁸

Furthermore the Transmission Regulation establishes that "...the just and reasonable costs of the transmission system are wholly charged to owners of electric distribution systems, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff..."²⁹

This means that costs associated with the regulating reserves and load/supply following are "costs of the transmission system". Therefore, although these costs appear to result directly from increased wind generation on the system, both the Transmission Development Policy and the Transmission Regulation support the interpretation that these costs will be allocated to load.

The level of reasonable procurement of these ancillary services is less clear and will need to be resolved. It is envisioned that a standard regarding forecasting accuracy be established to set a reasonable limit on ancillary services procurement and cost impact to load.

4.4 Wind Generator Power Management

The ISO has a duty to "direct the safe, reliable and economic operation of the interconnected electric system..."³⁰ This duty is put into practice by ISO Rule 6.7 which requires the system controller to "issue directives to market participants as required to prevent a threat to system security or to return the AIES to a safe and reliable state"³¹ and requires market participants to "use reasonable efforts to comply with directives from the system controller to prevent a threat to system security or to assist in the recovery from or return the AIES to a safe and reliable state."³²

Furthermore, as noted in section 4.2, the "must offer/must comply" obligation requires that all generators must comply with dispatch instructions from the system controller.

The Policy Framework also stipulates that "the variability of wind generation may create reliability concerns for the system operator, particularly as the amount of wind generation exceeds a certain threshold. The challenges include, control strategies, interconnection standards, volume/forecasting and potential system reliability impacts..."³³

The Policy Framework acknowledges that "wind is an interruptible source of generation; if the wind is not blowing there is no power."³⁴ The corollary to this assertion is that wind generation output can be controllable when the wind is blowing and if appropriate on-site wind power management technology is installed.

Therefore, the obligation of market participants to comply with dispatch instructions and directives from the system controller, in conjunction with the ability of wind generation to be controllable when the wind is blowing, supports the interpretation that wind generators must install power management technology as a condition of service, and that a wind generator must be able to comply with an instruction from the system controller to limit or impose ramp rate limits on its output.

4.5 "Constrained Down" Payments

The Transmission Regulation stipulates that the ISO must "taking into consideration the characteristics and expected availability of generating units, plan a transmission system that

(i) is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the Act when all transmission facilities are in service, and

(ii) is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy referred to in section 17(c) of the Act when operating under abnormal operating conditions....³⁵

It is important to note that the Transmission Development Policy recognizes that “given the lumpiness of transmission additions, the 95 % criterion is intended to be a guideline and not an absolute number. Congestion may occur during planned maintenance, forced outages of transmission facilities and/or some critical generation facilities.”³⁶ Given this context, the Transmission Development Policy explicitly states that “constrained down payments will not be paid to generators.”³⁷

4.6 Wind “Contingencies” and the Use of Contingency Reserves

The AESO Glossary of Terms for Technical Requirements for Ancillary Services defines a contingency as “the unexpected outage or failure of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.” It also defines Contingency Reserve as “an amount of Operating Reserve sufficient to reduce area control error to zero following the loss of generating capacity, which would result from the most severe single contingency all in a manner which adheres to WECC criteria.”³⁸

As a member of the Northwest Power Pool (NWPP) reserve sharing group and, as such, we carry contingency reserves based on the sum of 7% of load served by thermal, 5% of load served by hydro and 5% of load served by wind. The NWPP permits the use of these contingency reserves for an electrical trip or high wind speed cutout of a wind facility but does not permit the use of these reserves for loss of wind power due to a reduction of wind speed.

5. IMPLEMENTATION CONSIDERATIONS

The Market & Operational Framework has implications for all stakeholders in the electricity market. Wind generators assume responsibilities and costs for forecasting equipment and/or services, power management equipment and uncertain output reductions. Load assumes costs associated with increased ancillary services and necessary transmission reinforcements. All market participants may be impacted by increasing levels of in merit energy, increasing demand for fast ramping ancillary services such as regulating reserves and/or load/supply following or by new operating procedures needed to reliably manage operational issues such as surplus supply.

The Market and Operational Framework therefore defines the mitigation measures the AESO will use to manage variability, the order or priority of use of these measure, and obligations/cost responsibility for these measures. Uncertainties, such as forecasting and wind power management standards, Load/Supply Following service definition and technical requirements, and modified ISO rules or OPPs, still remain and will need to be resolved through open and comprehensive consultation. The framework will guide the AESO and stakeholders and form the foundation for work required to further refine and define rules, tools and procedures needed to integrate as much wind into the Alberta system as feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.

Implementation details will be developed, reviewed and finalized through existing and defined industry consultation processes. This may, at times, involve cross industry working groups collaborating with the AESO to develop proposals and recommendations for full industry consultation and endorsement. The following is a list of areas of work that will need to be completed over the next one to two years as wind generation increases and in preparation for large-scale wind integration:

- 1. Wind Power Management:**
 - a. Develop technical requirements for power management.
 - b. Finalize the interconnection requirements for wind power facilities.
- 2. Wind Forecasting:**
 - a. Develop interim requirements for real-time operations and continue with ongoing learning and improvements related to wind forecasting and the incorporation of same into AESO operational processes.
 - b. Complete the Wind Forecasting Pilot Project to further understanding regarding achievable and reasonable forecasting technical standards/requirements
 - c. Develop forecasting technical requirements to be incorporated into interconnection standards.
 - d. Develop market rules for wind power forecasting.
 - e. Develop cost recovery mechanisms (via tariff or energy trading charges)
- 3. Ancillary Services:**
 - a. Review regulating reserve capability, requirements and procurement practices in order to manage cost pressures associated with increasing volume requirements.
 - b. Develop the technical requirements and evaluate procurement alternatives for Load/Supply Following service.
- 4. Market & Operation:**
 - a. Review and revise/develop rules and/or operational practices, procedures (OPPs) and cost recovery mechanisms necessary to implement wind power management, wind power forecasting and other aspects of the framework. For example, OPP 103 defines the policies and procedures for the System Controller to dispatch multiple zero-dollar offers when system marginal price is at \$0, currently exempts all wind generation. However, this exemption can not be maintained at higher levels of wind penetration and OPP 103 will need to be modified accordingly.
 - b. Explore options for enhanced inertia capacity and/or capability that may facilitate wind power development (i.e. implementation of dynamic scheduling to enable additional regulating reserve and load/supply following volumes to participate in the Alberta market).
- 5. System Operator Tools:**
 - a. Develop or enhance tools for the System Operator to incorporate wind forecasting into operational processes.
 - b. Develop or enhance tools for the System Operator to effectively manage wind power ramp rates and/or volumes when required.
- 6. Interconnections:**
 - a. Update Interconnection Standards to include Wind Power Management, Forecasting and other necessary technical requirements.
 - b. Develop and implement improvements to Interconnection queue management practices
 - c. Develop and implement modifications to the interconnection proposal process necessary for large customer/project volume and new queue management practices

7. **Generation Plan:**
 - a. Develop a methodology for creating reasonable scenarios for wind generation development based on market and operational fundamentals.
8. **Transmission Planning:**
 - a. Advance transmission plans and need applications for immediate requirements
 - b. Develop transmission plans and applications required for generation in the queue
9. **Diversity:**

Although the ISO expressly does not have a role in the centralized planning of generation investments, it does have a responsibility to manage ancillary service and transmission costs. As a potential input and impact to requirements, diversity is of interest to the AESO. The AESO may conduct further investigation/study of wind power diversity anticipated in Alberta.
10. **Other:**
 - a. Reconcile the obligations of the framework with the current obligations of existing wind generators (possibility and practicality of grandfathering)
 - b. Explore methods to improve service to the market including increased market data/information transparency.

6. CONCLUSIONS

In a competitive generation marketplace, market participants and investors determine the appropriate type, location and timing of generation investments.

The Market & Operational Framework replaces the 900 MW threshold that was implemented in April 2006 allowing investment decisions regarding the supply portfolio in Alberta to be driven by market forces.

It is essential that the rights and obligations of all market participants are clearly defined and understood and a planned transition is clearly articulated and understood. The AESO will therefore be conducting a consultation session shortly to provide further explanation and clarity around the implementation of this Market & Operational Framework. The framework and subsequent refinement to rules and standards will provide added clarity allowing wind developers and other market participants to evaluate project economics with greater certainty and develop, in collaboration with the AESO, a reasonable forecast of wind generation development and advance transmission projects as appropriate.

Given the complex and dynamic nature of these challenges, the AESO believes that the solutions will evolve and will be refined and improved based on experience gained in future day to day operations as well as through research and collaborative consultation.

ENDNOTES

-
- ¹ Global Wind Energy Council: Global Wind 2005 Report
 - ² AESO: Incremental Impact on System Operations with Increased Wind Power Penetration
 - ³ AESO: Wind Integration Impact Studies
 - ⁴ Electric Utilities Act; Statutes of Alberta, 2003; Section 17(c)
 - ⁵ AESO: Wind Integration Impact Studies
 - ⁶ AESO: Wind Integration Impact Studies
 - ⁷ ISO Rule 6.7.1
 - ⁸ ISO Rule 6.7.2
 - ⁹ AESO: Wind Integration Impact Studies; page 31-34
 - ¹⁰ AESO: Incremental Impact on System Operations with Increased Wind Power Penetration
 - ¹¹ Ontario Wind Integration Study; October 6, 2006
 - ¹² Ontario Wind Integration Study; October 6, 2006
 - ¹³ Electric Utilities Act; Statutes of Alberta, 2003; Section 5(b)
 - ¹⁴ Electric Utilities Act; Statutes of Alberta 2003; Section 5(b)
 - ¹⁵ Electric Utilities Act; Statutes of Alberta 2003; Section 16
 - ¹⁶ Electric Utilities Act; Statutes of Alberta 2003; Section 17(b)
 - ¹⁷ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 47
 - ¹⁸ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 47
 - ¹⁹ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 48
 - ²⁰ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 5
 - ²¹ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 25
 - ²² Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 25
 - ²³ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 22
 - ²⁴ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 20
 - ²⁵ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 26
 - ²⁶ Electric Utilities Act; Statutes of Alberta 2003; Section 1(1)(b)
 - ²⁷ Electric Utilities Act; Statutes of Alberta 2003; Section 17(e)
 - ²⁸ Alberta Transmission Development Policy; December 2003; page 5
 - ²⁹ Alberta Regulation 174/2004, Transmission Regulation; Section 30(a)(i)
 - ³⁰ AESO: Electric Utilities Act; Statutes of Alberta, 2003; Section 17(h)
 - ³¹ ISO Rule 6.7.1
 - ³² ISO Rule 6.7.2
 - ³³ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 48
 - ³⁴ Alberta's Electric Policy Framework: Competitive-Reliable-Sustainable; June 2005; page 47
 - ³⁵ Alberta Regulation 174/2004, Transmission Regulation; Section 8(1)(e)
 - ³⁶ Alberta Transmission Development Policy; December 2003; page 8
 - ³⁷ Alberta Transmission Development Policy; December 2003; page 8
 - ³⁸ AESO Glossary of Terms for Technical Requirements for Ancillary Services