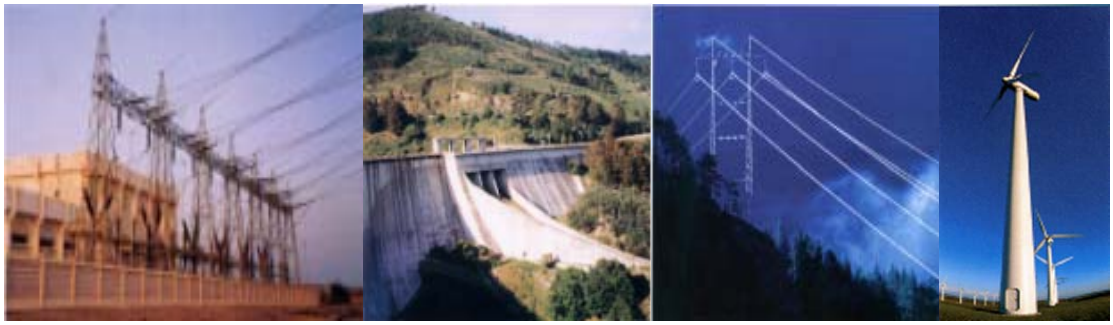
Alberta Province Report



Innovative Electricity Markets to Incorporate Variable Production

to

IEA – Renewable Energy Technology Deployment

May 2008

IPA Energy + Water Consulting

COWI A/S

SGA Energy

Innovative Electricity Markets to Incorporate Variable Production

to

IEA – Renewable Energy Technology Deployment

IPA Energy + Water Economics
41 Manor Place
Edinburgh
EH3 7EB
Scotland

Tel: +44 (0) 131 240 0840
Fax: +44 (0) 131 220 6440
Email: contact@ipaeconomics.com
web: www.ipaeconomics.com

TABLE OF CONTENTS

1 MARKET MECHANISMS

This section provides an overview of the operation of variable renewable generation within the Alberta market.

The Alberta Interconnected Electricity System (AIES) refers to the network of the Alberta transmission system for all generators, distribution companies and large industrial consumers. Contextually the AIES can be referred to as interconnected with its provincial neighbours British Columbia and Saskatchewan but unless otherwise specified in the text, any reference to the interconnected system in this section refers to the internal network of Alberta.

1.1 Renewable Generation Capacity

Alberta's electric generating capacity in 2006 was 11,760 MW. There are 280 generating units in Alberta which generated 65,300 gigawatt hours (GWh) of electricity. Coal-fired power plants (5,840 MW) generated 50 per cent of the province's electricity, while gas (4,440 MW) and hydro (869 MW) accounted for 38 and 8 per cent respectively. Wind and other generators contribute over 500 MW of capacity. Imports and exports across interties are provided with the neighbouring provinces of British Columbia and Saskatchewan.

In 2006, wind plants made up 387 MW of capacity, an increase of 363 MW since 1999. In 2006, the generation from wind was 922 GWh, an increase of 857 GWh since 1999. In addition to wind, Alberta also has Generating Capacity in other renewable energy sources, including biomass (184MW) and small hydro (900 MW)

There have been inquires from interested parties for 5,500 MW of additional generation. There have been concerns for system reliability if the system is burdened with an excess of non-dispatchable generation. Facing substantial wind additions in the near term the Alberta Electric System Operator (AESO) at one time established a temporary 900 MW threshold to ensure continued system reliability, which was removed in September 2007 after a number of recent studies sponsored by the AESO were better able to define the issues and to recommend solutions.

Existing measures to allow an increase in wind penetration:

- The Energy Market Merit Order (EMMO). EMMO currently balances supply and demand and is established at gate closing 2 hours before the delivery hour. EMMO in combination with regulating reserves can be dispatched as often as necessary to maintain supply demand balance.
- Regulating Reserves (capable of ramping in 10 minutes or less)

Possible future measures proposed to allow further increases:

- Load / Supply Following Services – this would introduce a new level of regulating reserves, slightly less rapid in response and therefore able to be met by a wider range of generators, the cost of these additional reserves would be borne by load as at present;

- Improved wind speed forecasting costs to be borne by individual wind generators; and
- Wind Generation Power Management and Control (effectively curtailment used when wind generation is too high), the costs of lost revenue and additional required equipment would be borne by individual wind generators

AESO also stress that geographic diversity would provide a measure of firm capacity for the wind portfolio. However, the system operator has no power to control this as the decision would be made by investors.

1.2 Institutions

Market Participants can be divided into the following major categories:

- **Generators**
  Generators sell electrical power through the Pool. Generators are currently divided into the following major categories:
  - **GENCO** Generating units under legislated obligations (as listed in the Electric Utilities Act) in companies such as ATCO Electric, EPCOR, and TransAlta.
  - **IPPS** Independent Power Producers.
  - **SPP** Small Power Producers regulated by the Small Power Research and Development Act.

- **Distributors and Direct Access Customers** (also known as Purchasers and DISCOs)
  Distributors generally serve municipal loads and purchase through the pool. Direct Access Customers are able to buy their energy directly through the pool. Their consumption of electricity is measured by a time-of-use meter. They also must be able to receive electricity from the interconnected electric system at a voltage level of 25kV or more and be able to increase or decrease its consumption of electric energy or system support services within 60 minutes of receiving dispatch.

- **Transmission System**
  Access to the electrical transmission system in Alberta is provided by the AESO. The AESO sets transmission tariffs, which are approved by Alberta Energy and the Utilities Board. Transmission access services continue to be a regulated monopoly, which offers non-discriminatory access to all persons wishing to exchange energy through the pool.

- **Independent System Operator** (AESO)
  The AESO facilitates Alberta's wholesale electricity market, which has about 200 participants and about CAD[1] 5 billion in annual energy transactions, and is accountable for the administration and regulation of the load settlement function. The AESO provides fair and open access to the Alberta Interconnected Electric System (AIES) for generation and distribution companies and large industrial consumers of electricity, and contracts with transmission facility owners to acquire transmission services and provide

[1] Canadian dollars

customer access. The AESO is independent of any industry affiliations and owns no transmission assets. Consistent with its responsibility to ensure system reliability, the AESO procures ancillary services, including operating reserves, to address contingencies and moment-to-moment changes in load. The company manages the exchange of electric energy and system support services between Alberta and its neighbouring jurisdictions. To do all this the AESO:

- Determines the economic merit order for energy dispatch.
- Sets the schedule for dispatching generating units.
- Reports the pool price for each hour.
- Carries out financial settlement for the electric energy exchanged through the pool.

- **System Controller**
  The System Controller dispatches generation and import offers in economic merit order to meet system and export demand. The Controller is also responsible for ensuring the safe and reliable operation of the system and for providing adequate levels of system support services.

- **Market Surveillance Administrator**
  Alberta's Market Surveillance Administrator (MSA) is in place to monitor Alberta's electricity market for fairness and balance in the public interest. Market Surveillance keeps a close watch on the overall performance of Alberta's electricity market - checking that it operates fairly, efficiently and in an openly competitive manner.

1.3 Renewable Generation and Power Markets

The AESO is an open-access market that accepts Bids and Offers on electricity, and trades electricity on the lowest price basis. The market is a spot market, which matches demand with the lowest cost generation to establish an hourly pool price. Access to the market pool is available on a non-discriminatory basis to all generators, distributors, importers, and exporters that meet the qualifications set by the regulators.

As an alternative to buying and selling electricity at the wholesale market prices, participants can participate in Net Settlement Instructions (NSI). These allow buyers and sellers of electricity to enter directly into contracts for a fixed amount of power at a fixed price over a specified time period in the future. These offer a stable pricing arrangement that customers and generators can use to hedge against volatile electricity prices. All participants eligible to buy directly from the Pool are eligible to set up an NSI with any participant eligible to sell to the pool. The AESO manages the NSI contract (without knowing the contract price) by managing the scheduling and dispatch of power. The contract can be for all or some of the buyer's load. The buyer is guaranteed supply and price of power. The generator is liable if they fail to provide power as scheduled. In this system, the generator is charged the spot market price for any shortfall between the scheduled and dispatched quantities. Both participants pay a settlement price to AESO for the management services

Wind generation is a non-dispatchable market participant and thus a price taker ($0 offer) which may reduce price returns, increase risk and in turn reduce potential for its development from an economic perspective. Wind generation in Alberta

therefore relies on mechanisms such as Net Settlement Instructions (NSI) with green power premiums to remain competitive in the Alberta market.

The premiums in the form of Renewable Energy Certificates can be sold with the electricity or separately as a commodity. An example of such a transaction follows:

> Commencing 1 September 2001, Calgary Transit (Calgary, Alberta) entered into a partnership with the local municipal LDC and a private Alberta wind developer to purchase the GHG credits from the wind system equivalent to the electricity demand from its transit system. Using wind-generated power currently reduces CO_2 emissions by 26,000 tonnes annually.

Wind plants typically operate as merchant plants (as do the majority of developers in Alberta), meaning that generators are paid the hourly pool price for the electricity that is delivered to the grid. The generator will sell the environmental attributes separately to buyers in the form of a Renewable Energy Certificate or similar emission credits.

1.4 Degree of Centralization

Control of variable wind development is, like all generation development in the province, subject to market rules of supply and demand and as such is decentralized to the power market. The uniqueness of variable generation is recognized by virtue of being non-dispatchable and of placing constraints on system reliability.

Alberta has deliberately set out to establish access to the power pool on a non-discriminatory basis to all generators, distributors, importers, and exporters that meet the qualifications. Variable generation is therefore free to develop on the basis of unique social and environmental properties it may provide as long as it conforms to market rules.

1.5 Support Mechanisms

Supports exist for wind generators from provincial government, federal government and regional utility agencies.

There are currently no directly sponsored programs by the province for the support of wind or other variable generation technologies. On the other hand, ninety per cent of the electricity used in government facilities is procured from green power sources, such as a wind farm in Southern Alberta, through concessionary NSI. Also, Alberta is the first jurisdiction in North America to have regulations in place to reduce greenhouse gas emissions. Starting July 1, 2007 Alberta facilities that emit more than 100,000 tonnes of greenhouse gases a year are required to reduce their emissions intensity by 12 per cent under the *Climate Change and Emissions Management Act.* Targets have been shown to be a stimulus for investment in carbon offset projects which can result in long-term NSI contracts for wind farms.

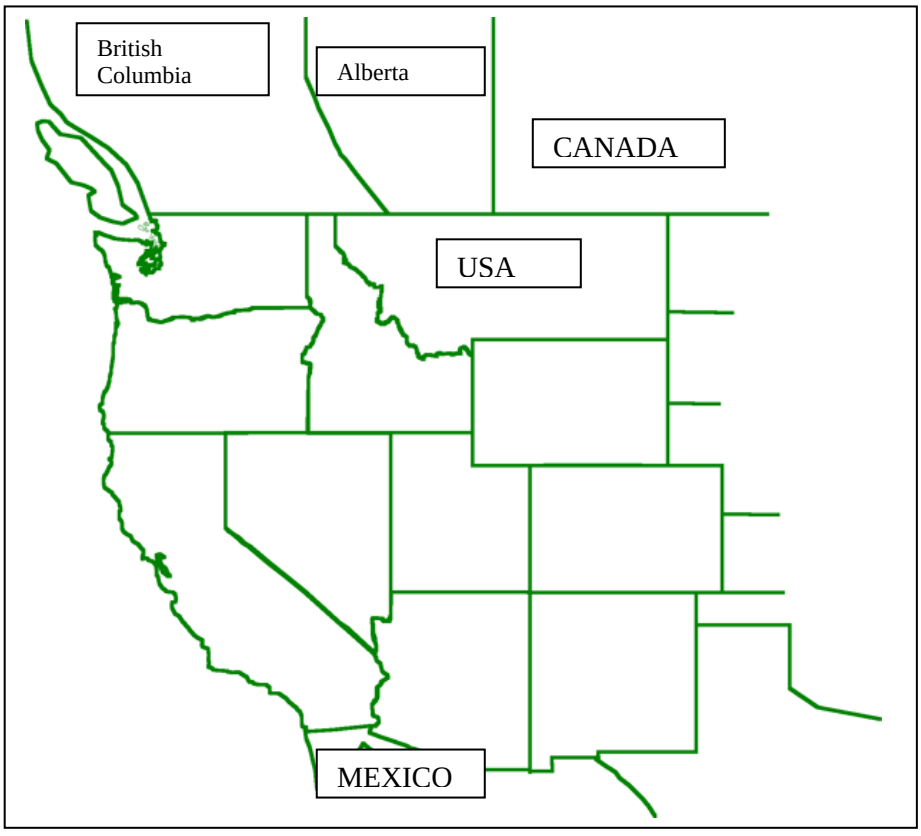
There is one federal program which is eligible within Alberta, the Canadian federal government ecoEnergy program. ecoENERGY for Renewable Power provides an incentive of CAD 0.01 / kilowatt-hour for up to 10 years to eligible low-impact,

renewable electricity projects (including wind) greater than 1 MW constructed in the four year period April 1, 2007 to March 31, 2011.

The Alberta System is also part of the Western Electricity Coordinating Council, an affiliation of U.S. States and Canadian Provinces that are part of the Western transmission interconnected system. As of June 2007, this agency helped establish and now is home to the Western Renewable Energy Generation Information System or WREGIS, a renewable energy registry and tracking system for the Western Interconnection. The role of WREGIS is to develop and implement a system tracking renewable energy generation. This system will help ensure the credibility of the "green" value of renewable electricity and facilitate the growth of renewable energy throughout the Western U.S. and Canada.

Participation in WREGIS is voluntary. Besides Alberta WREGIS will be available in the area covered by the Western Interconnection System, which covers 14 States, 2 Provinces and part of Baja California (Washington, Oregon, California, Nevada, Idaho, Utah, New Mexico, Arizona, Colorado, Wyoming, Montana, Texas, South Dakota, Nebraska, British Columbia, Alberta and the northern portion of Baja California, Mexico).

Figure 1: The WREGIS System Coverage



Electricity generated from renewable energy comprises two distinct tradable commodities – the underlying electricity and the associated “environmental” attributes. Renewable energy certificates (known as WREGIS certificates if issued by WREGIS) represent a contractual right to the environmental attributes. The WREGIS certificates have value to consumers and can be sold separately from the electricity.

Account Holders are expected to include load serving entities, balancing authorities, generators, marketers, regulators and others. WREGIS account holders will buy and sell their certificates on-line. Small distributed generators are allowed to participate.

There are expected to be multiple benefits of WREGIS which ultimately has the aim of expanding RE generation. These benefits include:

- Prevent double counting of green credits
- Verify quantity of RE generated in the Western Interconnection
- Issue and retire Renewable Energy Certificates (RECs) with unique serial numbers
- Track RE transactions at the wholesale level
- Enable verification of compliance with state/ provincial RE policies/programs
- Enable Verification of green power claims
- Facilitate commercial trading of RECs
- Create REC transaction reports for regulators
- Be compatible with other REC tracking systems to facilitate imports and exports of RECs

1.6 Trading

All generators (transmission or distribution connected) are required to register with the AESO as supply assets. Any generator equal to or above 5 MW in size (whether distribution or transmission-connected) must submit bids and be dispatchable (this includes hydro). The one exception is wind which may forecast its bid as non-dispatchable but is always a price taker (i.e. they have standing $0 bids and operate at will). Units below 5 MW are also generally price takers.

A small charge per MWh (about 13.5 Canadian cents) is assessed by the AESO as a trading charge.

For the next day's trades, Participants must have their Bids and Offers submitted and accepted by 12:00 noon. After 12:00 noon, the Participant is automatically prevented from revising the next day's Bids and Offers. Advance Bids and Offers (for trading beyond the next business day) may be submitted at any time. By 12:00 noon, all generators and importers submit Offers, for each one hour period, for the next seven days. Offers are structured in incremental MWh volume blocks, with each increment being offered at the same or a higher price than the previous block. They include the asset's Constraints and Total Declared Energy. Offer prices for the next day are fixed and are not subject to revision. All other Offer prices for the subsequent six days can be revised as necessary.

A Standing Offer or Bid indicates that the Participant wants to apply the same submission into the future, until the Participant chooses to change it. Once a submission exists for a particular date it will not be overwritten.

Currently, intermittent wind generators do not submit bids or even forecasts for the next day trading. As discussed their bid is implicitly $0 and they will take what is given as the hourly spot price.

Market rules are changing to Must Offer / Must Comply. This means that market participants are obliged to submit bids or offers. The compliance and forecast implications for variable generators have not been worked through and uncertainty remains for these market participants. However, the system operator recommends that this is translated to a "must forecast" requirement for wind, and that individual generators should bear the cost of any additional equipment required.

1.7 Dispatch and Notification

The System Controller dispatches electricity according to the merit order, and within the constraints set by the Bids or Offers submitted by the Participants. When dispatching electricity, the System Controller takes into account:

- All the information submitted in the Bids and Offers by all Participants.
- The applicable merit order, unit schedules, and forecast unit dispatch that has been prepared for the next day.
- Total Declared Energy and Supply Shortfall Energy
- Any system support services or transmission constraints.

1.8 Imbalance Settlement

The AESO coordinates and manages settlement by providing daily and monthly settlement reports and issuing Statements. Settlement reports indicating energy volumes traded and associated payables or receivables for each Participant are made available on the AESO web page throughout the month as metered volume data becomes available. Final Statements for settlement of accounts are released 15 business days after the end of each monthly production period.

There is no energy imbalance service or charge in Alberta. The AESO is responsible for balancing the system and does so through the energy market, operating reserve market and other ancillary services. Appropriate scheduling behaviour is encouraged through compliance standards/rules. In Alberta the load customers (ratepayers) pay for ancillary and operating reserve services.

Currently the AESO rules require generation assets greater than 5 MW to generate at a level of ±5 MW of their energy market dispatch level. Exceptions to dispatch non-compliance are considered when it is not physically reasonable for the generating asset to attain compliance. The System Operator does not currently distinguish between dispatchable and non-dispatchable assets. Under the current rules, however, non-dispatchable wind is not required to forecast generation levels and therefore is not expected to meet the dispatch tolerances of ±5 MW. Future compliance requirements for these assets have yet to be worked out.

There are financial penalties specified in the rules regarding the energy market. The AESO attempts to change non-compliant behaviour by first raising the issue

with participants and through warnings. Only when these are unsuccessful in changing behaviour do penalties escalate to financial sanctions.

1.9 System Balancing

Balancing supply and demand is the responsibility of both the AESO and the market participants. The AESO has responsibility for balancing the system after gate closure (10 minutes ahead of real time). The AESO does its own forecasting to determine the size of the overall block based on submitted schedules of the participants or counterparties. Participants assist system balancing through accurate forecasting up to gate closure.

In the event of system imbalance the AESO can call on ancillary services or operating reserves to meet unexpected load demand. The portfolio is made up of three classes (Active, Standby and Supplemental). All reserves are procured daily in a competitive market via the Alberta Watt Exchange Limited (Watt-Ex) and an over the counter (OTC) market. Watt-Ex (now owned by Natural Gas Exchange (NGX)) is a private, online trading system for electricity Ancillary Services in Alberta. To be eligible to provide operating reserves, market participants must meet the standards provided by the AESO, in particular of ramping through the regulation range within 10 minutes.

1.10 Summary

The 387 MW of wind generation in Alberta represents just over 3% of its mainly thermal generation capacity. Previously, concerns for system stability led to a declared cap of 900 MW on variable wind generation. However, multistakeholder consultation and wind studies have led the AESO to lift this cap in conjunction with adjustments to market rules. Firm rules for variable generators have not yet been established but may include a requirement for improved forecasting of generation and the ability to manage and control output to the grid.

The AESO is an open-access market that accepts Bids and Offers on electricity, and trades electricity on the lowest price basis. The market is a spot market, which matches demand with the lowest cost generation to establish an hourly pool price. Access to the market pool is available on a non-discriminatory basis to all generators, distributors, importers, and exporters that meet the qualifications set by the regulators. Non-dispatchable wind generation is currently allowed on the market without forecasting its input. Because it is a non-dispatchable market participant it is a price taker ($0 offer) which means it is assured dispatch at the hourly spot market price.

Wind generation assets can rarely be financially viable at spot market rates. With the help of provincial, municipal and other power consumers generators are able to market Renewable Energy Certificates (REC) or other emission credits bundled separately from the energy component. A significant market mechanism was introduced in June 2007 to assist in the brokering of REC. The Western Renewable Energy Generation System (WREGIS) encompasses 2 Canadian provinces (including Alberta) and 14 US states. WREGIS provides the certification, validation and brokering mechanism for REC for account holders within, and eventually outside, the region.

2 CROSS BORDER TRADING

Currently Alberta is connected to electricity systems of its two neighbouring provinces, British Columbia (B.C.) and Saskatchewan (SK.). Alberta also exports to and imports from the U.S. through the BC intertie. Electricity exports and imports to and from these markets are permitted under the Market Rules of the AESO; however, compliance with bordering utility regulations is necessary. Cross border electricity traders must therefore become familiar with general access rules, regional regulatory bodies and the regulatory structures in each jurisdiction.

2.1 Current Cross Border Flows

The Alberta electricity market has two links to external systems. These are a major intertie with BC (1200/1000MW path rating) and a DC tie to Saskatchewan (150MW). The interties provide access to the North American electric grid. The BC intertie connects to the U.S. Pacific power markets, members of the Western Electric Coordinating Council (WECC). On the east side through its Saskatchewan intertie, Alberta is linked with the Mid-Continent Area Power Pool (MAPP).

The province is relatively poorly interconnected with its neighbours. The interconnection capacity as a percentage of peak load is lower in Alberta than any other province in Canada (approximately 12% in Alberta compared to about 40% in British Columbia). Also, Alberta electricity imports and exports are low compared to other provinces. Alberta has the lowest import/export capacity among major utilities in the Western Electricity Coordinating Council (WECC). Alberta is generally a net importer of electricity. Only in 2001 did exports exceeded imports, due to the unusual circumstances of market failure in California and the resulting lower prices in Alberta compared to neighbouring markets.

Nevertheless, Alberta, Saskatchewan and B.C. engage in important trade on a daily basis that takes advantage of the difference in the generating technologies in the two provinces. Alberta imports power during peak periods, especially the late afternoon and early evening, and then returns off-peak power. This enables Alberta's predominantly thermal-based generation system to run at a relatively constant, and therefore more efficient, rate through the entire day while B.C.'s predominantly hydro-based system can be operated to accommodate the peak, and then store water behind its dams at night.

The Alberta-BC interconnection is comprised of one 500 kV transmission line and two 138 kV lines. The British Columbia portion of the tie-lines is owned by BC Hydro and operated by the BC Transmission Corporation (BCTC), while the Alberta portion of it is currently owned and operated by AltaLink.

The AESO and BCTC are parties to an Interconnection Agreement that establishes the conditions for operating the Alberta-BC Interconnection. BCTC has been the WECC-designated Path Operator for the interconnection. As of December 2007, however, AESO has been established as path operator for BC-AB interconnection as a result of a NERC[2]/WECC audit.

[2] See Annex D

Scheduling of power flows on the intertie is coordinated between BCTC, which is responsible for the interchange transactions on the BC side, and the AESO, which is responsible on the Alberta side. The scheduling process of interchange power flows is complicated on both sides of the interchange. AESO, however, manages a competitive market where several market participants have the opportunity to trade on the tie-line. Theoretically BC Hydro offers open access to its tie-line through BCTC but has almost exclusive access to its domestic transmission system with the exception of point to point trades.

Alberta has been a net importer of electricity for the past several years.

2.2 Cross Border Capacity Mechanisms

In Alberta the AESO facilitates an open-access market that accepts Bids and Offers on electricity, and dispatches electricity on the lowest price basis. The AESO receives Offers and Bids from participants in MW blocks for each hour of the next day. Prices offered for the next day are binding for all Bids and Offers while energy blocks associated with prices can change up to T-2. All Bids and Offers must be submitted by 12:00 Noon for the next trading day.

Imports are offered into the market as “Price Takers” at $0.00 for each MWh block of energy. This ensures dispatch for imports. Exports bid into the AESO at the maximum price to ensure that they are not used in the home market, but are exported to supply external contracts. Imports and exports are set to be price takers because they are generally scheduled one hour in advance and cannot respond to inter-hour market dispatch instructions.

The schedule for the Intertie starts at hh:00[3] and ends at hh:60 – interchange schedule changes within the hour are not allowed to change except for system security reasons or the delivery of emergency energy. Between hh:30 and hh:40, the transaction information is transferred to either BC or SK transmission operators, and at hh:40, the AESO and applicable TSO confirm the net interchange schedule, the ramp start time, the ramp duration and the NERC tags for the next scheduling hour.

Regarding imbalance settlement, in Alberta uplift to settle imbalances is not imposed on generators, importers or exporters so that a charge is neither paid to importers nor charged to purchasers for imbalances. At the same time transmission congestion preventing delivery is considered an Acceptable Operating Reason for not complying with a dispatch. In other words, transmission constraints allow the market participant the ability to 'back out" of the dispatch order. In this situation, that offer/transaction would be removed from the merit order (for energy market) or supply stack and the dispatcher would move up the merit order or stack accordingly.

2.2.1 Potential Future Intertie Capacity

A recent study commissioned by the California Energy Commission projects that by the year 2030 California will need 23,000 MW from imports and an additional 8,300 MW of transmission interconnections to

[3] Time shown as hh:mm. Therefore hh:00 means on the hour, e.g. 17.00

supplement their existing 18,200 MW interconnection capacity. The AESO's 20 year plan states that it is actively participating in the "Canada-California Transmission Study Group". The objective of the Canada-NW-California studies is to provide high-level information on the feasibility of potential transmission projects to transfer a variety of new resources out of Canada into the Northwest and California.

Among the options considered was a Montana Alberta merchant tie line of 300 MW. Construction permission has been approved, with conditions by various regulatory agencies. The target for commissioning is 2009. Among all of the United States, Montana is rated number five for wind energy potential and the developers point out the positive effect of the new interconnector on the development of wind power projects.

Another important development that could significantly increase Alberta's exports is the surplus of electricity that could come about from cogeneration in the Fort McMurray area which is the centre of oil sands development in Alberta. One proposal is to send the power via a merchant transmission line (the Northern Lights Transmission project) into the mid-Pacific North West area of the U.S. The Northern Lights Transmission Line would be capable of carrying 2000-3000 MWs. It is proposed that the line would likely be a merchant facility independent from the regulated transmission grid and that tolls and tariffs would be negotiated between shippers and the transmission line owner.

2.3 Cross Border Trading

AESO Market Rules for interchange transactions have been established to align with or meet industry standards and are 1 MW blocks firm for the hour. The Market Rules also specifically require NERC tags as do bordering American jurisdictions. NERC has further reinforced these regional standards by establishing these as North American intertie standards for all Regional Transmission Operators and the eight Regional Reliability Councils. In other words exports and imports amongst all North American utility jurisdictions are ruled by a universal trading format. See the appended description of NERC for more details.

Although path rating for imports to Alberta from BC are rated at 1200 MW this flow is rarely acceptable for AESO system operation. Normally, the total transfer capacity for the BC to Alberta intertie is 760 MW while the firm transfer limit is set at 545 MW. Conversely, export to BC is rated at 1000 MW. The BC limitation on the transfer from Alberta to BC is currently 600 MW. Most of the time there are limitations inside Alberta which prevent operation at this level. There are several reasons for the operation limits. Alberta imports are limited by reliability criterion limiting the capacity of the largest single capacity contributor: the interconnector works as a very large generating unit, supplying energy to Alberta. Exports, on the other hand, are limited, especially at peak periods, because of insufficient transmission capacity constraining voltage levels.

Even apart from the physical and operational constraints on the intertie, the capacity that is available is often under-utilized. Regardless of Alberta supply and demand at any one time, there are numerous times in a year when it is simply uneconomic to schedule out of or into Alberta given relative market conditions (e.g. better terms available at the California-Oregon border).

The different market structures of the transmission region also constitute an impediment to the full utilization of interconnection capacity. The interrelationship between Alberta's pool price, prices in neighbouring markets, and the flow on the transmission interconnections is complicated by the fact that Alberta's two closest jurisdictions are not deregulated markets. The electricity market design is very different between the provinces and the connected U.S. western states. Alberta is the first Canadian wholesale and retail competitive marketplace, having an energy market that is dispatched on the basis of advance offers into the market; monopoly jurisdictions generally dispatch in real time. The pool price for Alberta buyers and sellers alike is not known until after the fact. British Columbia and Saskatchewan are each a single buyer market, where the single buyer purchases a planned amount of power from competing independent power companies.

Also, regional US markets have completely different market structures. The largest is a bilateral market where buyers and sellers seek each other out in order to complete a transaction. The spot market for power is a decentralized over-the-counter market; prices are negotiated by traders at various utilities, not in a centralized market. The electric grid presents difficult coordination problems among scattered injection and delivery points on a complex network. In these markets, prices are known prior to delivery of the energy and most trades are transacted day ahead over on- and off-peak strips. There is also a liquid hourly market required by participants to make adjustments to circumstances occurring in real time.

There is leeway for smaller increment spot market import / export (even up to 5 minutes) given the approval of RTO submissions to the NERC. To take advantage of the opportunity Alberta would require a coordinated submission from the jurisdictions involved. Preliminary study is currently underway within the WECC. In the event, however, imports and exports would still be required as firm and dispatchable thereby eliminating wind as a candidate for intertie imports or exports.

The AESO procures a portfolio of operating reserves that are consistent with Western Electric Coordinating Council (WECC) and NERC standards. To be eligible to provide operating reserves, market participants must meet the standards identified in the technical requirements provided by the AESO. Imports are eligible to participate in the ancillary services market just as other generators or supply points offering Spinning and Supplemental Reserves. Importers must pre-qualify and bid as ancillary services via the Alberta Watt Exchange Ltd. an arms length entity created to provide ancillary services. Wind imports or exports would not qualify for ancillary services because of the non-dispatchable nature of their supply.

2.4 Renewable Support Mechanisms

As a member of WECC, Alberta can avail itself of the Western Renewable Energy Generation Information System (WREGIS). WREGIS is an independent, renewable energy database for the region covered by the Western Interconnection. WREGIS tracks verifiable renewable generation from units that register in the database. WREGIS certificates can be verified, tracked and sold separate from the kWh that created them. The implication is that variable-generated energy may face flow constraints at interties amongst jurisdictions. On the other hand, WREGIS certificates mean that green premiums associated with renewable generation do not

have to face the same constraints as scheduled MW exports / imports and can flow easily on a regional or eventually a national basis.

WREGIS was developed as a collaborative process between the Western Governors' Association, the Western Regional Air Partnership, and the California Energy Commission. The development was further guided by stakeholder input from more than 400 participants gathered over a period of more than three years.

2.5 Utilisation for Variable Generation

There is no evidence that wind or other variable generation currently makes use of any interties. Imports and exports must participate as dispatchable day ahead participants. Wind is non-dispatchable.

2.6 Summary

Alberta interconnects with adjacent provinces British Columbia and Saskatchewan. Interties are significantly under utilized. For example, the BC intertie allows 1200 MW import and 1000 MW export but both are utilized at rarely more than 60% of this capacity. Reasons for this are varied but have to do with issues such as congestion within Alberta's transmission network or the impact of better pricing elsewhere in the Region. Alberta accesses the US market generally through its BC intertie. Alberta remains a net importer largely because of price differences between its domestic fossil-fuelled generation and relatively inexpensive hydro electricity available from BC and NW US States.

The Alberta ISO, the AESO, dispatches imports and exports in keeping with market rules for all participants. Energy is offered or bid in 1 MW blocks up to T-2 at prices that are binding for the day ahead.

Significant growth of demand in Western US States, particularly California, has stimulated plans for merchant transmission lines linking Alberta generators directly with the US markets.

Given that intertie transactions require firm dispatchable, hour-ahead bids and offers as an industry standard in North America, variable generation is not viable as an import / export commodity. On the other hand the "green credits" associated with variable, renewable energy are negotiable across borders without requiring physical transfers. As a member of the Western Renewable Energy Generation Information System (WREGIS) which is dedicated to tracking and verifying green credits, Alberta supports the growth of variable generation on its system. It is too early to forecast the impact that mechanisms such as WREGIS will have on the growth of variable generation since carbon markets are at a nascent stage in North America.

3 GRID PLANNING

3.1 Grid Investment

AESO has responsibility for:

- Developing operational and long-term transmission expansion plans,
- developing short- and long-term load forecasts of customer and generator access requirements,
- forecasting operation and long-term system technical requirements to meet customer demand, and;
- forecasting annual system costs and billing volumes for tariff design.

It is the AESO who contracts with transmission facility owners to acquire transmission services and provide customer access. The AESO, however, is independent of any industry affiliations and owns no transmission assets.

The costs of operating the transmission system are recovered through the AESO's transmission tariffs, approved by the Alberta Utilities Commission (AUC), and have been structured to achieve a fair allocation of costs among stakeholders and to support a competitive market.

Over the last 20 years, the AIES[4] has doubled with no major upgrades to the transmission backbone. There are currently no major deficiencies in the transmission system but it is operating at or near system limits more often. Effects of this are:

- System management becomes more dependant on generation – both MW and MVArs
- Complex operating procedures are required to deal with dynamic operating conditions
- The system is experiencing some degradation of service and areas of congestion
- The availability of transmission capacity to relatively small decentralized generators is restricted.

These transmission constraints, with other factors led to the moratorium have a particular impact on wind energy. According to the AESO, there is more than 9000 MW of wind in the queue.[5]

[4] The Alberta Interconnected Electricity System (AIES) refers to the network of the Alberta transmission system for all generators, distribution companies and large industrial consumers. Contextually the AIES can be referred to as interconnected with its provincial neighbours British Columbia and Saskatchewan but generally within this document any reference to the interconnected system refers to the internal network of Alberta.
[5] Correspondence with Andrei R. D. Nikiforuk, Alberta Department of Energy, 27 March 2008

3.1.1 Planning Process

Overall planning is through the 10-year plan and 20-year outlook documents. As part of the planning process, the AESO conducts several formal and informal consultations with industry stakeholders.

As a member of the Western Electricity Coordinating Council (WECC), Alberta has chosen to adopt the WECC Reliability Criteria for application in Alberta as well as its interconnections. The AESO Transmission Reliability Criteria summarizes important elements of the WECC Reliability Criteria and identifies applicable performance standards and interpretations used in planning and operating the Alberta Transmission System.

The NERC/WECC Planning Standard require systems to meet Category B (N-1) requirements while accommodating planned outages and maintenance of any bulk electric equipment. The AESO intends to meet the above standard with the exception of Local Networks. The bulk electric equipment considered is limited to transmission circuits, transformers and protection systems.

NERC/WECC Planning Standard:

- **Category A** represents a normal system with no contingencies and all facilities in service. This is often referred to as the **N-0** condition. The system must be able to supply all firm load and firm transfers to other areas. All equipment must operate within its applicable rating, voltages must be within their applicable ratings and the system must be stable with no cascading outages.
- **Category B** events result in the loss of any single specified system element under specified fault conditions and normal clearing. The specified elements are: a generator, a transmission circuit, a transformer or a single pole of a DC transmission line. This is often referred to as an **N-1** event or with the most critical generator out of service, an **N-G-1** event. The acceptable impact on the system is the same as Category A. Radial customers, including loads or generators, are allowed to disconnect from the system. The loss of opportunity load or opportunity interchanges is allowed.
- **Category C** events result in the loss of one or more specified system elements under specified fault conditions and include both normal and delayed fault clearing events. When any two specified system elements are lost simultaneously, this is referred to as an **N-2** event. All of the system limits for Category A and B events apply with the exception that planned, controlled loss of either firm load, firm transfers and/or certain generation is acceptable provided there is no cascading.
- **Category D** represents a wide variety of extreme, rare and unpredictable events, which may result in the loss of customer demand (firm load) and generation in widespread areas. The system may not be able to reach a new stable state. These events need to be evaluated for risk and consequences. The WECC is currently drafting the “Extreme Contingency Guide” to provide additional guidance around this class of event.

The Transmission Regulation requires the system operator provide for a system adequate to allow for transmission annually of 95% of electricity that is "in merit" (i.e. generators should normally have grid access to transmit electricity when they are in the dispatch portion of generation offers into the electricity pool.) However, 95% is not an absolute or guaranteed figure, and no constraint payments are made if a generator does not have access.

3.1.2 Offshore

Alberta has no coastline so that offshore development is not applicable.

3.2 Planning & Security Standards

The Alberta system has specific grid code requirements which affect all grid entrants including variable generators such as wind and hydro. Requirements include:

- Turbine reactive power control;
- System voltage control;
- Voltage ride through capability; VRT requirements are applicable to all transmission connected generating facilities where the wind facility aggregated MW Capacity is greater than 5 MW. The AESO will continue to monitor development of facilities 5 MW and less and may revise the MW threshold.
- Fault protection / interruption and ride through capability;
- Frequency tolerance;
- Isolation switching;
- Information provision – fixed data and operational metering.

The AESO worked in collaboration with stakeholders from May through November 2004 to develop wind power facility technical requirements for interconnection to the Alberta Interconnected Electricity System (AIES) for generators over 5MW. The full costs of these controls have not been assessed as a burden to wind generators.

- **Production Limits and Control:**

  Telemetry must allow the AESO to monitor system output and control that output directly or indirectly through the windfarm operator. All turbines must not be allowed to stop or start simultaneously and ramp up rates should be controlled.

- **Low- voltage ride-through (LVRT):**

  All wind turbines should be able to ride through a normally cleared single or multi-phase fault at the high-side (transmission voltage level) of the substation transformer. For more prolonged disturbances, where the system

voltage does not recover for an extended period of time (significantly beyond normal clearing times), the wind turbines in the farm must be tripped by under voltage protection.

- **Voltage Regulation and Reactive Power Requirements:**

  A wind farm must have a capability to be a net generator or absorber of reactive power. It should be able to generate a net amount of reactive power equal to roughly one half of its peak Megawatt output (or more). A wind farm with a capacity greater than 5 MW shall provide an Operator that can be contacted by the AESO System Controller on a 24 hour basis.

- **Verification Tests:**

  Verification tests must be performed to demonstrate that the wind farm meets all of the requirements of for example, the low voltage ride-through capability as well as the performance and response of the reactive power controller.

The system operator has also recently indicated [1] that they expect participants to be able to comply with instructions from the system operator. Clearly, wind farms cannot generate if the wind is not blowing. However, it can curtail despatch when the wind is blowing. Therefore, their view is that wind generators should install power management systems as a condition of service.

3.3 Transmission Access & Charging

In Alberta the power pool is an open-access market that accepts Bids and Offers on electricity, and dispatches electricity on the lowest price basis. The AESO receives Offers and Bids from participants in MW blocks for each hour of the next day. The System Controller of the AESO dispatches electricity according to the merit order, and within the constraints set by the Bids or Offers submitted by the Participants. When dispatching electricity, the System Controller takes into account the transmission constraints of the system. With dispatch, participants are automatically given access to transmission.

Cost recovery for the transmission facilities and for operating reserves is entirely factored into the wires usage rate paid by load customers. Generators do not pay ongoing charges for transmission facilities and operating reserves. The only charge most generators, including wind, face is a charge for system losses. This charge is based on an annual loss factor allocation and determines whether a generator adds to or reduces system losses. It is possible in the latter case for the charge to in fact be a credit.

The replacement of the 900 MW Reliability Threshold for wind generation with a new framework for wind integration by the AESO escalates the importance for amending the Interconnection Process to improve efficiencies of approvals. The AESO is working to minimize delays outside of the control of market participants identifying and formalizing the approval processes for transmission connection and access as well as the times expected for approval. In the future, queue positions will be established to give priority to a project. Process milestones must be met by interconnection proponents to maintain queue priority. Failure to comply will mean the loss of queue position and application fees.

3.3.1 Transmission Connection

System customers (both generator and load) gain access to the grid through application to the AESO. The first step is a Preliminary Assessment Application (PAA) used to establish queue position and to allocate transmission capacity and work priority to projects on a first come, first serve basis. The AESO then works with the Transmission Facility Owner (TFO), the customer and other stakeholders and regulators to achieve requested in-service dates. Milestones are established, which they must meet in order to maintain queue position, work priority, and allocated transmission capacity.

The interconnection process is important not only for providing equitable customer access to the grid but also for giving the AESO planning insight for an allocation of transmission capacity, the application of remedial action schemes in the event of transmission constraints, or other operational and technical requirements required for interconnection. Customers may not gain access until grid capacity is assured and any required grid reinforcement is done. Access is managed according to queue position.

Current demand for transmission service far exceeds capacity in certain congested regions of Alberta, giving rise to discussions aimed at improvements to the Interconnection Process and market and operational changes to accommodate new customers. There is especial recognition that a new liberalization of allowable wind generation capacity (formerly an upper threshold of 900MW) escalates the urgency for amending the current Interconnection Process. There is concern for example that projects not progressing through the Interconnection Process (for example because of congestion in certain regions) will not be permitted to block access to transmission capacity for projects that are proceeding.

In particular the AESO is currently facing a significant number of applications for wind connections in the South of Alberta which has problems with congestion. To meet concerns over project delays and approvals for connection the AESO has instituted the following measures:

- Get transmission reinforcements in place in a timely fashion;
- Give priority for each project to inform wind customers if transmission reinforcements are required to provide unconstrained access;
- Group projects into zones;
- Apply the project queue to each zone rather than an individual project;
- Plan individually with the customer the timing and detail of an Interconnection Plan (IP);
- Where requested, prepare simplified IPs that include load flows, +/- 50% estimate,

- Upon customer acceptance of IP, assign a project manager and proceed through rest of the process

3.3.2 Connection Charging

Generators are responsible for paying local interconnection transmission charges as managed by the AESO.

Transmission-connected generators pay 3 basic charges (two of which are refundable) to get connected:

- **Application fee:**

  To connect to the transmission system a generator files an application for interconnection (called a Preliminary Assessment Application) and pays a fee. If they proceed to connection, the fee is refunded. The fee is based on the ultimate contract capacity. This charge is roughly based on application processing costs.

- **Direct interconnection costs (shallow costs):**

  To connect the generator to the transmission system the Transmission Facility Owner (TFO – the regulated owner/operator of the transmission grid) must generally install a tap point and build new transmission line to the generator's substation. In addition some protection upgrades are generally needed at the tap point and adjacent system substations to accommodate the new generator. These are roughly the "direct connection costs" – i.e. the costs to install the radial line for the generator connection. These costs are born by the new generator.

- **System costs (security against deep costs):**

  In addition, the grid may also need upgrading (transformer changes, line upgrades, protection modifications) further upstream or on the looped network (the grid). These are generally deemed "system costs" and not charged to the new generator. To ensure, however, that new generation is not causing undue "system upgrades" without becoming active servers of the system load, new generators pay a refundable Generator System Contribution Payment when they commit to proceed with TFO construction. The security payment is required to secure the applicant's position in a queue for approvals. This is normally a cash security deposit held without interest. For smaller applicants this can represent a barrier.

The payment is not based on whether or not any system upgrades must occur or how much they cost. The payment is variable depending on the area of the province; it is less in areas which are load rich/generation poor, it's more in areas which have a generation surplus – in effect this is a "location signal" to new generation to encourage new generation, if possible, to locate near load. The Generator System Contribution Payment is refundable over a 10 year period based on generator performance criteria established as annual average capacity factors. Different generation types have different performance criteria. Currently the annual capacity factor performance criterion for wind generation is 20%. Penalties apply on the

refund of the Payment for under or over performance. The rules permit leeway to allow for over-performance with notified reason.

As mentioned above, at the time of application a refundable connection contribution is required to secure the applicant's position in a queue for approvals. This is normally a cash security deposit held without interest. Those wind projects applying but constrained by the afore-mentioned 900 MW Reliability Threshold were permitted to substitute cash security with a Letter of Credit to maintain a queue position. Now that the Threshold restriction has been dropped wind applicants are required to revert to a cash security deposit. For smaller wind applicants this deposit applied without interest can represent a barrier.

3.3.3 Transmission Access

The obligation of the system operator is that the system should be adequate to allow for transmission annually of 95% of electricity that is "in merit" (i.e. generators should normally have grid access to transmit electricity when they are in the despatch portion of the electricity pool.) However, 95% is not an absolute or guaranteed figure, and no constraint payments are made if a generator does not have access.

3.3.4 Transmission Charging

Under the transmission development policy, generators are responsible for local interconnection charges and a financial commitment and payment towards system upgrades. Generators do not pay ongoing charges for transmission facilities and operating reserves.

The balance of transmission costs are allocated to load. Since 2006, cost recovery for the transmission facilities and for operating reserves has been 100% factored into the use of system rate paid by load customers. Thus any ancillary costs associated with regulating reserves and load/supply following which might justifiably be associated with a variable generator such as wind will in fact be allocated to load.

3.3.5 Transmission Losses

Generators, including wind, must pay a location-based loss charge. All losses are allocated to generation based on specific criteria. This charge is based on an annual loss factor allocation. Varying methodologies are used in different jurisdictions for the allocation of losses among all generating units.

A complex calculation involving metered energy inputs and location specific loss factors determines whether a generator adds to or reduces system losses. Loss factors generally range from -5% (favourable) to +10% (unfavourable). Favourable loss factors actually produce a credit.

3.4 Summary

In Alberta, wind development has been constrained in certain areas of the province due to transmission congestion. With the removal of the cap on wind assets, it is anticipated that the demand for connection will increase. To counter this, there are plans for increased transmission capacity and improved management of queuing and approval processes.

The connection charging regime may prove difficult for smaller or more remote generators, since they are required to provide a refundable security deposit based on the deep costs of connection.

ANNEX A – ABBREVIATIONS AND ACRONYMS

Acronym	Definition
AESO	Alberta Electricity System Operator
AIES	Alberta Interconnected Electricity System
AUC	Alberta Utilities Commission
B.C.	British Colombia
BCTC	British Colombia Transmission Corporation
CAD	Canadian Dollar
EMMO	Energy Market Merit Order
FERC	Federal Energy Regulation Commission
GENCO	Generating Company
GW	Gigawatt = 1,000,000 kW (unit of power/ capacity)
GWh	Gigawatt hour = 1,000,000 kWh (unit of energy)
IEA	International Energy Agency
IP	Interconnection Plan
IPPS	Independent Power Producers
kW	Kilowatt = 1,000 Watts (unit of power/ capacity)
kWh	Kilowatt hour = 1,000 Watt hours (unit of energy)
MAPP	Mid-Continent Area Power Pool
MSA	Market Surveillance Administrator
MW	Megawatt = 1,000 kW (unit of power/ capacity)
MWh	Megawatt hour = 1,000 kWh (unit of energy)
NERC	North American Electricity Reliability Council
NGX	Natural Gas Exchange
NSI	Net Settlement Instructions
NTC	Net Transfer Capacity
OTC	Over The Counter
PTR	Physical Transmission Rights
REC	Renewable Electricity Certificate
RETD	Renewable Energy Technology Deployment
SK	Saskatchewan
SPP	Small Power Producers
SO	System Operator
TSO	Transmission System Operator
TWh	Terrawatt Hour = 1,000 MWh (unit of energy)

Acronym	Definition
Watt-Ex	Alberta Watt Exchange Ltd
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

ABBEX B – GLOSSARY

Term	Definition
Bilateral	Trades or other contracts between two participants, for example a generator and supplier.
Capacity	Cf. Energy, Power. The maximum ability of a generating station to generate an amount of electricity in a given time. Measured in units of power (kW). The actual energy generated is dependant on the load factor.
Clip Size	The minimum size of interconnection capacity contracts.
Credit Cover	The cash or other financial security that must be provided.
Day Ahead	The day prior to the day that is being traded for or balanced.
Deep Connection Costs	Cf. Shallow Connection Costs. The costs of reinforcing and upgrading the wider network to enable additional generation or demand to be connected.
Energy	Cf. Power, Capacity. Formally defined as the ability for a system to do work. In the case of an electrical energy this is measured in kWh. Energy cannot be stored in the transmission network, so at any given time the total energy generated must equal the total energy demand and total losses (due to heating of wires etc.) This is known as balancing the system.
Gate Closure	The last time at which energy can be traded before the markets are closed. Balancing trades may take place closer to real time on a separate balancing market.
Group Processing	This means that the grid operator puts applicants into a queue and groups them into areas or zones. Reinforcement is then carried out on selected zones to accommodate the applicants in that zone. There is no guaranteed timescale for connection.
Intraday	Within the day that is being traded for or balanced.
Locational	Cf. Postage Stamp. Differentiated by geographical location. For example, in the case of transmission charging, this typically will mean higher charges further from demand centres.
Long	Cf. Short. Where a participant has more generation than is required to balance their demand (including losses where applicable)
Merit Order	The order that a system operator will place generators in based on the costs to deliver a certain quantity of generation. Those generators that will allow the forecast demand to be met at the lowest costs (subject to system constraints) are described as being in the merit order and are despatched.
Postage Stamp	Cf. Locational. Uniform, equal throughout the network.
Power	Cf. Energy, Capacity. Power is the ability to create energy in a given time, and can be expressed in the following equation: $$Power(kW) = \frac{Energy(kWh)}{Time(h)}$$

Price Maker	Cf. Price Taker. In the context of an electricity pool, a price making generator will submit a number of bids/offers indicating how much electricity they would be prepared to despatch at a given price. The system operator will place the generators in order of cost to determine which plants will be despatched.
Price Taker	Cf. Price Maker. In the context of an electricity pool, a price taking generator will not submit a bid or will submit a bid at zero. This means it will always be despatched (subject to system constraints) and will receive the pool price. Price taking generators include variable generators with low marginal costs, such as wind.
Real Time	The actual time period that energy is being traded for or balanced.
Shallow Connection Costs	Cf. Deep Connection Costs. The costs of physically connecting a generator to the nearest appropriate point in the transmission network, this may typically be the closest substation. This does not include costs associated with any required reinforcements to the wider transmission network.
Short	Cf. Long. Where a participant has less generation than is required to balance their demand (including losses where applicable)

ANNEX C – REFERENCES

Number	Reference
1	AESO Market Operational Framework for Wind Integration in Alberta, 7 March 2007
2	AESO 10 Year Transmission System Plan 2007-2016 (February 2007)
3	AESO Transmission Reliability Criteria, Part II System Planning, Version 0, 11 March 2005
4	AESO website http://www.aeso.ca/
5	Wind Power and Electricity Markets, Utility Wind Integration Group, Information compiled through September 21, 2007
6	North American Electric Reliability Corporation Standards website https://standards.nerc.net/
7	North American Electric Reliability Corporation website http://www.nerc.com/
8	Wind Power Facility Technical Requirements, Revision 0, 15 November 2004

ANNEX D - THE NORTH AMERICAN ELECTRICITY RELIABILITY COUNCIL (NERC)

The North American Electricity Reliability Council (NERC) is responsible for aspects of an international electricity system that serves 334 million people, and has some 211,000 miles (340,000 km) of high-voltage transmission line throughout North America. The certification of NERC in 2006 has been the result of concerns for maintaining a high level of reliability throughout the North American grid.

NERC develops and maintains reliability standards, including regional reliability standards, that apply to bulk power system owners, operators, and users. Regional reliability standards, when approved by the Federal Energy Regulatory Commission (FERC) in the U.S. and in Canada the National Energy Board (NEB) along with provincial regulatory authorities, are made part of the body of NERC reliability standards. These are enforced upon all bulk-power system owners, operators, and users within the regional entity's region, regardless of membership in the region. As of Sept 2006 the NEB recognized NERC's role in Canada as Electric Reliability Organization for a North American interconnected system. The National Energy Board signed a Memorandum of Understanding promoting reliability standards for international power lines under the NEB's jurisdiction which covers all international bulk power exchanges. This agreement recognized the role of NERC in developing reliability standards for North America's bulk power grid. Although the NEB will continue to regulate international power lines that fall under its jurisdiction, NERC will monitor these lines in Canada to ensure compliance with its reliability standards. The NEB receives regular reporting from NERC concerning NEB regulated power lines. These reports are used to identify international power lines that are non-compliant with NERC's reliability standards.

Important standards developed by FERC and promoted through NERC relate to reciprocity principals for all members requiring non-discriminatory access to transmission lines within a member's jurisdiction. Members therefore enjoy open and equal access to each others transmission systems. NERC holds no legal enforcement power, however, the system is based on very strong reciprocity. Not supporting NERC policies could result in reduced openness by other systems. In practical terms Canadian provincial utilities must comply with the decisions of regional councils. NERC policies are, however, based on strong consensus and do not create onerous compliance requirements for competently run systems.

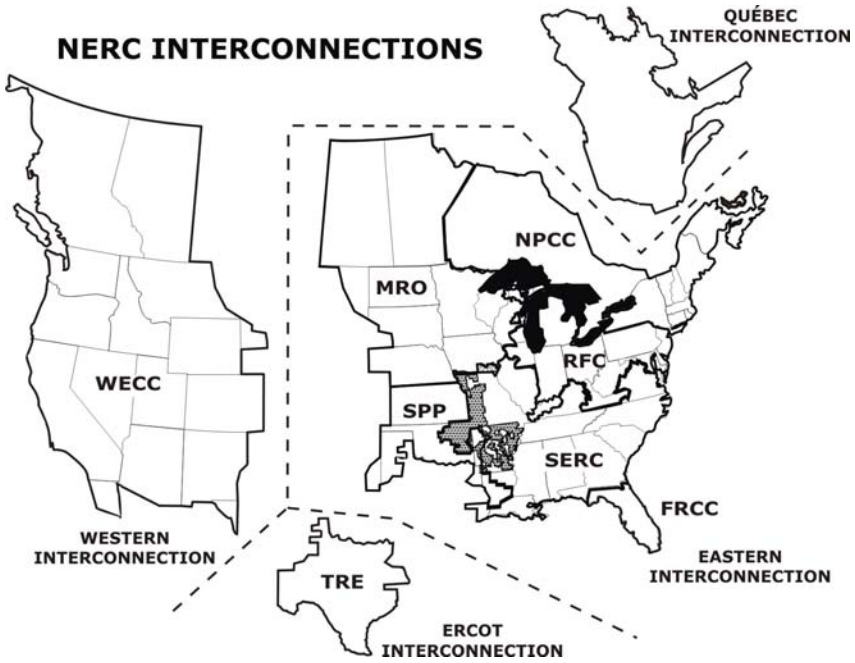
NERC works with eight Regional Reliability Councils to improve the reliability of the bulk power system. The members of the regional councils come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. NERC's proposal to delegate enforcement authority to eight regional entities is pending before the Federal Energy Regulatory Commission. These eight councils are as follows:

Regional Reliability Councils
Florida Reliability Coordinating Council (FRCC)
Midwest Reliability Organization (MRO)
Northeast Power Coordinating Council (NPCC)
Reliability*First* Corporation (RFC)
SERC Reliability Corporation (SERC)
Southwest Power Pool, Inc. (SPP)
Texas Regional Entity (TRE)
Western Electricity Coordinating Council (WECC)

The figure below positions each Regional Council geographically. Ontario falls within the NPCC, Alberta within the WECC.

A significant development for member imports and exports intra and inter regions is NERC tagging. Implemented in July 1997 long before full certification of NERC, tagging requires bulk electricity transfers between systems to be "tagged". A tag is an electricity transmission schedule with a specific path, for a specific duration, over a specific time frame. Copies of the tag are distributed to all systems that could be affected by the electricity transfer. These systems must apply their non-discriminatory transmission access rules to either approve or deny the path requested in the tag. A central agency collates the results. If all affected systems approve the transaction, the electricity transfer takes place as scheduled in the tag.

Figure 2: The North American Regional NERC System



The NERC Compliance Monitoring and Enforcement Program works to ensure compliance by all bulk power system owners, operators, and users with NERC reliability standards approved by applicable governmental authorities. Bulk power system owners, operators, and users are required to register with NERC and comply with all approved reliability standards and report all violations of the reliability standards to their regional entity. NERC also actively monitors registered entities for compliance with a select number of reliability standards. Through delegation agreements, each regional entity carries out the NERC compliance monitoring and enforcement program. NERC oversees each regional entity's compliance monitoring and enforcement process; each region is responsible for reviewing and enforcing compliance with all registered entities within the region.