

# **AESO Market Road Map Review:**

## **Load Coalition Comments**

The Load Coalition, consisting of the Alberta Direct Connect Consumers Association (ADC), the Industrial Power Consumers Association of Alberta (IPCAA) and the Utilities Consumer Advocate (UCA) thank the AESO for the opportunity to comment on the Market Road Map.

Two key changes are now under way in Alberta’s electric industry: wind integration is advancing rapidly, and transmission development is expected to proceed expeditiously. Longer term changes are also on the horizon, including stronger integration with neighboring markets, and the potential development of northern hydro and nuclear generation.

Rather than dealing with the many side-effects of these changes, the Load Coalition recommends that two over-arching initiatives be launched by the AESO, within which several of the proposed initiatives might have a more meaningful context.

- **“Pool pricing mechanism review”** is necessitated by the impending occurrence of zero pool prices, as baseload and wind resources compete for a place in the merit order.
- **“Transmission access review”** is necessitated by Alberta’s increasing interconnections with other markets, and by the probability that transmission congestion will continue to be an issue, as it is in most jurisdictions.

A timely review of these fundamental questions will prepare Alberta for the resumption of rapid growth which is anticipated as the current recession eases. This window of opportunity can be used to prepare Alberta for its future, in keeping with the vision articulated in Alberta’s Provincial Energy Strategy.

### **1 Demand Response: An Urgent Concern**

The urgency of restoring the tie-lines to their rated capacity is highlighted in Section 16 of the Transmission Regulation. The participation of customers in ILRAS (and now LSR procurement) is clearly an essential component of this process, and merits a high priority attention. This also integrates with the procurement of ancillary services and the operating reserves market.

### **2 Review of Pool Pricing Mechanism**

#### **2.1 Origins of Alberta’s Pool Pricing Mechanism Market Structure**

*A Transitional Pool Price Mechanism*

When Alberta’s current market design was implemented in 1995, coal and natural gas were the only generation technologies given serious design consideration. Traditional unit dispatch procedures were based on unit fuel efficiency: the most efficient units are run first and the least efficient are run last. Those traditional procedures were re-used in designing Alberta’s new competitive generation market.

At the time, there was no obvious alternative. Customer choice did not exist until 2001, and requiring generators to enter into bilateral arrangements with utilities would have effectively recreated the managed market model. Price discovery through an administratively established market price would in theory allow new generators to estimate their potential revenues and thereby justify their investments in new units.

In practice, essentially no new generation was built under this model, and market prices exploded in 2000-2001. In the subsequent furor of implementing retail competition and then dealing with the collapse of house-of-cards trading empires, the 1996 mechanism was left in place. As the years passed, other jurisdictions developed various alternative approaches—but the shortcomings of Alberta’s pioneering, stopgap mechanism were well understood, and it fell into relative disrepute.

#### *Benefits of Generation Competition*

It was also recognized in 1996 that the greatest benefits of generation competition would be realized as the existing generation fleet was replaced in coming decades. A competitive market structure leaves the decision as to which generation technologies should be built completely up to independent investors. This would eliminate the need to convince utility staff and regulators of the relative merits of new technologies—investors would take the risk, and reap the rewards of new and more efficient technologies, while customers would benefit through the rapid introduction of more cost-effective innovations.

The long-term benefits of generation competition are now beginning to be realized. In particular, the substantial carbon cost penalties associated with greenhouse gas emission have eliminated traditional coal from the long-term generation mix, and will have a significant impact on natural gas generation as well in the long term.

The economics of emerging generation technologies are very different from what was contemplated in 1994—as expected. Competitive market forces continue to be the preferred approach to dealing with these new economic realities.

#### *Economics of New Generation Technologies & Pool Prices of Zero*

Four main technologies are currently seen to be capable of delivering Alberta’s long-term energy requirements— wind, hydro, coal (with carbon capture and storage) and nuclear.

These technologies have one common characteristic—competition based on incremental fuel efficiency is not meaningful. Wind and hydro have essentially no incremental fuel cost. Coal with CC&S will be driven by the high capital cost and the need to produce CO<sub>2</sub> for injection as well as electrical energy. Nuclear plant costs are virtually all fixed, and the units cannot be cycled in response to changing market prices—they must run as continuous base-load operations.

As a result, it can be reliably forecast that pool prices of zero will become an increasingly common occurrence. The vast majority of hourly market prices are already being “hollowed out”, yielding generator revenues that often do not even cover fuel costs, while a small number of unpredictable, extremely high-priced hours yield virtually all of generator fixed-cost coverage. This inefficient pricing ripples through the forward market, and since there is no physical delivery requirement, the forward market also oscillates erratically.

The transitional 1996 pool pricing mechanism is being pushed far beyond its ability to deliver satisfactory pricing for either customers or generators. Its failure point is imminent, as the market price heads steadily towards zero (or below).

## **2.2 Resolution of Zero Pool Price: Managed Market or Competitive Market**

### *Managing a “Zero Pool Price”*

The current pricing mechanism forces the AESO to create a “managed market”, in which administrative rules are used to dispatch down zero-priced generators. This is fundamentally incompatible with Alberta’s market structure, in which competition determines generator operation.

Rather than proceeding further down a demonstrably inferior path of command and control, now is the time to consider competitive alternatives. The market is the preferred forum in which to assess the balancing of dispatchable and non-dispatchable resources, since that is ultimately where the tradeoff between supply alternatives is made.

### *Physical Bilateral Arrangements*

The general solution path appears to be the use of **physical bilateral arrangements**, in which each customer specifies to the AESO the dispatch steps to be taken with its contracted physical supply resources. In some respects, this would not be a material departure from the status quo, since most load is largely covered by bilateral arrangements of one form or another. However, from an operating perspective, the market would have to provide the AESO with instructions whose content and timing has yet to be explored. This is the physical aspect of bilateral arrangements which is critically missing from the current mechanism. The 1996 pool pricing mechanism could then continue as an imbalance market to settle variations from scheduled flows.

Another review of capacity market options does not appear to be necessary or relevant to this question. Capacity markets are a regulatory construct, not a market

construct, and the use of these capacity markets perpetuates a disconnect between the financial flows and the physical reality of the electricity system. Long-term planning tools and approaches must be resurrected, reserve criteria established, and complex price adjustments and rules implemented—none of which deals with the zero price problem. Alberta’s current problem is a potential capacity surplus, not capacity shortage, and complex shadow pricing schemes are not the answer.

At the core, markets are about delivery of real, physical products at an unconstrained, mutually agreed upon price, and the more closely Alberta’s electric industry follows the fundamentals of all markets the simpler its design and operation will become.

### **2.3 Practical Concern: Cogeneration Operations**

Cogeneration operations demonstrate the urgent practical concerns that must be addressed.

In many cogeneration activities, electricity is a byproduct of a primary production process such as extracting bitumen or petrochemical production. The primary process has a heat requirement which must be met, and generation output is by design inextricably linked to that process as a byproduct.

Consider the case where a large company owns both electricity-producing cogeneration operations and energy-consuming load operations at a distant location. The electricity output of the cogeneration process is fixed by process requirements, but the company’s load operations can more than absorb this output.

The cogenerator is economically willing to chase the price down to absurdly negative numbers in order to be dispatched and allow the primary production process to continue at full volume. The pool price is irrelevant, because the cogenerator has a physical contract for differences with his own operations; but all other generators would suffer as the official market clearing price sinks.

Pro-rata curtailment is not an option—the operation must function at full volumes as it was designed. Negative pricing would solve the dispatch decision, but could then create grave financial hardship for generators and market disruption.

This is not a theoretical concern—over 2,000 MW of cogeneration capacity in Alberta faces this dilemma right now.

### **2.4 Recommendation: Review of Pool Pricing Mechanism Alternatives**

It is appropriate that a review of alternative pool price mechanisms begin at the AESO, since this is fundamentally an operational dispatch problem, not a policy question. If industry reaches consensus on a technical solution, then its policy implications can be explored in a broader consultative context; if no consensus solution emerges, then policymakers will at least be aware of the problem’s difficulty, and of the options that exist.

Given the imminence of a ‘zero pool price’ regime, it is recommended that this initiative be given a high priority in the AESO’s workplan.

## **2.5 Related Issues: Pool Price Cap & Interties Setting Price**

The pool price cap question is clearly secondary to the continuation of the existing pool pricing mechanism. Accordingly, it is recommended that unless compelling reasons for immediate change are identified, further review of the cap be postponed until the zero price question has been resolved.

If the cap is to be removed, it should be removed completely—and unconstrained negative as well as positive offers permitted.

Similarly, the question of interties setting price is a secondary issue, which should be considered in a broader context. Rather than dealing with the symptoms of this problem in unconnected contexts, it would be more efficient to address the fundamental issue.

Intertie pricing is critically important to the development of Alberta’s world-class wind resource. To the west, there are tens of thousands of megawatts of hydro, whose energy shaping abilities are already fully developed. Integrating Alberta’s resources with these external markets demands integrated pricing as well.

These are fundamentally economic observations, all of which can be modeled and their impacts assessed. A broad-based process will allow parties to undertake studies and analysis which may be beyond the AESO’s legislatively limited mandate, but which could shed light on the broader market issues underlying Alberta’s interaction with its neighbors.

## **3 Transmission Access**

### **3.1 Origins of Alberta’s Transmission Pricing Regime: Cost Pooling & One System Planning**

Electric service began in Alberta’s largest cities in the early 1900s. Over time, cities were interconnected and by the 1970s the Alberta Integrated System (AIS) had grown to cover the entire province.

Twentieth century industry evolution was dominated by the ever-increasing economies of scale of generation units—the bigger the unit, the lower its costs. In the 1970s, a 400 MW coal unit was the optimal frame size, balancing economies of scale against the province’s ability to economically absorb large generation additions. Acting in the broad public interest, regulators made it clear that only 400 MW units would be permitted.

However, the cost of adding a 400 MW unit to an 800 MW utility would be crushing—rates could well double in a single year.

To balance the needs of one system planning with small utilities’ constraints, a cost pooling system was created in 1983. The “Electric Energy Marketing Agency” (EEMA) averaged all generation and transmission costs into a single unit demand and energy rate which was then charged to all customers.

In 1996, integrated generation planning and cost pooling were replaced with a competitive market structure—but integrated transmission planning and cost pooling has continued to the present day. A corollary of this older model endures—the absence of any form of transmission access rights within a ‘socialized’ transmission development framework.

### **3.2 Structural Transmission Issues**

If transmission additions could be quickly and inexpensively completed, this traditional framework might be entirely workable. Unfortunately, social attitudes have changed, and transmission development has become tortuous and unpredictable.

This problem is exacerbated by the speed and uncertainty of generation development. Generating units can be built much more rapidly than transmission lines, and their location cannot be predicted. The only way to deliver the legacy policy of unconstrained transmission availability is to build large amounts of excess capacity well in advance of its need—recognizing that if generation projects do not proceed as anticipated then some of this excess capacity may never be used and the costs borne by customers.

Alberta’s restructuring was founded on the objective of transferring decision-making authority and risk away from regulated bodies, and putting it in the hands of the market. Building transmission before there is an irrevocable commitment from generators to use this capacity is effectively transferring business risks onto unwilling customers. As new approaches to transmission development are implemented, this risk transfer must be objectively assessed.

This situation also creates generator concerns, as established investments can find their transmission access reduced by new plants, and have no means of ensuring ongoing access.

As Alberta develops more interties with other jurisdictions, and seeks to integrate merchant transmission lines, this province’s lack of firm transmission rights may grow even more problematic. Traders may be forced to buy transmission rights up to the Alberta transfer point—at which point local congestion may block the transaction. These ‘seams issues’ merit immediate attention.

### **3.3 Recommendation: Add “Review of Transmission Access” to Market Road Map**

It is recommended that the AESO include a “Review of Transmission Access” in its workplan, with a high priority. The scope of such a review might include problem definition, analysis of solutions used in other jurisdictions (particularly by Alberta’s

trading partners), and ideally a broad consensus position. This could then be used by policy-makers in determining whether changes are appropriate, and in framing stakeholder consultations.

This does not imply that the policy of customers paying for transmission service must be reopened. Customers can be the sole purchasers of transmission access in order to facilitate their commercial arrangements. The fundamental question concerns firm transmission rights, a matter which has been at issue in AUC proceedings for many years, and continues to remain unresolved.

### **3.4 Related Issues: Existing Inter-Tie Capabilities, Congestion Management, Dispatchability of Interties, Available Transmission Capacity**

This broad range of related issues supports the proposal to view this matter comprehensively, rather than as a set of isolated issues. A broad analysis will also be of assistance in dealing with these related questions, rather than pursuing them in piecemeal isolation.

## **4 Structuring the Market Road Map**

Given the preceding proposals, the Market Road Map might be structurally grouped as follows:

### **Pool Pricing Mechanism Review**

- Pool Price Cap
- Interties Setting Price

### **Transmission Access Review**

- Existing Inter-Tie Capabilities
- Congestion Management
- Dispatchability of Inter-Ties
- Available Transmission Capacity

### **Operational Market Issues**

- Operating Reserves / AS Procurement / Demand Response
- Wind Integration
- Market Systems Visioning

**Specific Policy Implementation**

- Draft FEOC Regulation
- T Reg Sec. 18 Rules (Generation Emergency Operation)
- Market Suspension Rules

Notwithstanding the diversity and complexity of these issues, grouping them around a small number of major structural questions will help focus energy on the fundamentals. Once the basic principles have been addressed, the individual issues should fall into a more coherent pattern.