ECONOMIC WITHHOLDING IN THE ALBERTA ENERGY MARKET

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Power Pool OF ALBERTA

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EXECUTIVE SUMMARY

Concerns about market power have been a significant feature of the restructuring debate since the first competitive markets were proposed for electricity. In every restructuring debate, market power has become an issue of concern.

The purpose of this paper is to respond to the Power Pool Council directive for Market Development to consult with industry about developing a benchmark that defines the limits of economic withholding.

The aim of this paper is to define economic withholding, assess its impact on the marketplace, and recommend mitigation approaches if required. It also serves other purposes including:

- development of common language around the economic terminology for market power;
- reference to mitigation options and rules in other markets;
- examination of the impact of economic withholding in Alberta; and
- development of both short term and longer term recommendations for Alberta.

Economic withholding is defined as an exercise of market power intended to raise prices in the market above competitive levels by pricing offer blocks high enough to effectively "withhold" or reduce the quantity of supply that is offered at "competitive" prices. There continues to be a debate around how "competitive" levels are defined and measured; nonetheless, the practice of submitting offer blocks at high, non-competitive prices is defined as economic withholding.

For the purpose of this analysis, the Pool has continued to focus on the exercise of monopoly power by suppliers rather than on monopsony power by loads. Market power usually focuses on supplier market power since very few loads have the ability to constrain their consumption strategically in order to control prices.

An analysis of the competitive characteristics of the Alberta wholesale marketplace (Section 3) indicates that the market is generally able to respond to market changes (price, volume, etc.) except in specific situations. For example, in the real-time market where both demand and supply elasticity (response) is lowest due to import restrictions and start up constraints the impact of economic and physical withholding could be significant in some hours.

While many jurisdictions in the U.S. have developed extensive market mitigation rules and guidelines in response to market power issues (see Appendix), there is a cost benefit policy tradeoff for mitigation of market power. The Pool would like to minimize interference in the marketplace and instead recommends focusing on addressing the market power issue where the impact is the greatest – i.e., during the real-time ("RT") delivery hour.

The following recommendations focus on the specific performance of the Power Pool of Alberta's real-time market. These are designed to address potential specific competitiveness issues arising from economic withholding in the hour of physical delivery.

- Preservation of the price cap as a "damage control" cap, in order to limit the distortions and transfers that might be created by a unforeseen market flaw or exercising of market power. The appropriateness of the price cap level at $1,000 should continue to be monitored and consideration given to raising the limit to facilitate other market objectives such as increasing demand side participation.
- Revision to the locking restatement rule to prevent very short-term market power from being exercised – it is recommended that the locking restatement cannot be used to change offer volumes for the current and next hour.

Based on analysis done to date, further intervention through market rules is not required as the market is relatively competitive and accordingly responsive to market changes.

It is also recommended that the following work be undertaken to support market competitiveness:

- Further work on market information and access thereof to ensure that the market obtains the information it needs to be competitive, but that market power cannot be exercised through information access.
    - An examination of reinstatement of the merit order graph will be conducted within the context of the market information analysis.
    - Improvement in the price forecasting methodology for real-time forecasts to encourage market response. Since market response is key as an input to how much mitigation is required, further efforts are warranted in ensuring that the market receives sufficient and timely information, especially regarding price.
- Further development of market monitoring procedures, along with the development of appropriate measures to determine whether the Alberta energy market is operating competitively; and
- Further development of market monitoring procedures to examine incidences of physical withholding, especially in concert with non-competitive offers.

1 INTRODUCTION

Concerns about market power have been a significant feature of the restructuring debate since the first competitive markets were developed for electricity. The debate has been strengthened by the evolving understanding of the special characteristics of electricity as a commodity, experiences in some jurisdictions with price spikes, and the complexity of the transition from heavily regulated utilities to competitive suppliers. In every restructuring debate, market power has become an item of concern.

Regulation and competition are substitutes, though some of each can be required. Where competitive forces can be relied on in markets to produce efficient and acceptable outcomes, there is minimal need for regulatory intervention. Where competitive forces are likely to be insufficient, the scope for efficiency-improving intervention rises. This paper provides a recommendation to what an acceptable balance might be in Alberta.

This paper was prepared with assistance from Frontier Economics, Inc. (Cambridge, MA). The Power Pool of Alberta is responsible for final content.

1.1 OBJECTIVES

In the context of electricity markets, horizontal market power of suppliers has often been characterized as “economic” or “physical” withholding. The former term is the subject of this paper; however, economic withholding as a term is often too narrowly defined. Both “economic” and “physical” forms of market power are highly interrelated, and should not be assessed in isolation.

This paper is meant to advance a policy discussion; it is not an economic treatise. While some economic logic and terminology must inevitably be employed, it is not the intent to provide a full economic treatment of the subject of market power in electricity markets. The economics employed is constrained – it is hoped – to the level needed to develop sensible policy conclusions and develop rule changes.

The purpose of this paper is to respond to the Power Pool Council directive for Market Development to consult with industry about developing a benchmark that defines the limits of economic withholding. To achieve this directive, the following objectives are outlined for this paper:

- to define the concept of economic withholding,
- to assess its possible effects on the Alberta electricity market, and
- to make recommendations on what measurement and mitigation is required, if any.

This will be accomplished through an analysis of the Alberta market and other North American markets, and through consultations with Alberta stakeholders and deregulation experts.

One mitigation option – limits on the use of the locking restatement – is examined in this paper. Further analysis will be provided in a separate paper regarding market information availability, and an analysis of the extent to which market information could support or impair the competitive market.

1.2 ORGANIZATION

The remainder of this paper is organized in six sections:

- Section 2 defines economic withholding and the concepts of perfect and imperfect competition, and discusses why economic withholding is a critical question in electricity markets;
- Section 3 briefly assesses the determinants of competitiveness in the Alberta wholesale electricity market, based on supply and demand balance, load responsiveness, forward hedging opportunities and other characteristics of well-functioning markets;
- Section 4 outlines the approaches that can be used *ex post* to assess the competitiveness of electricity markets and the detailed behavior of market participants;
- Section 5 develops a qualitative cost-benefit framework for assessing regulatory policies with regards to economic withholding and market power mitigation; and Section 6 concludes with an assessment of Alberta's market development, suggesting policies that are consistent with local conditions.
- Section 7, the Appendix, illustrates how these techniques have been used in other jurisdictions, including the United States, the United Kingdom and Canada.

2 MARKET POWER IN ELECTRICITY MARKETS

Much of the discussion regarding market power issues has been conducted in general, intuitive terms. Further progress on these issues requires clear language and consistent terminology. In this section, we develop a more structured framework for discussing market power based on standard economic principles.

2.1 ECONOMIC DEFINITIONS

Market power is often defined as the ability to profitably and sustainably increase prices above competitive levels. This definition implies that two aspects of market power are of particular relevance:

- What is the appropriate benchmark for "competitive price levels"?
- How severe or prolonged a deviation from a competitive outcome is acceptable, if any?

This first issue requires further consideration of precisely what we mean by a competitive outcome, while the second is a policy decision that balances the cost of potential regulatory interference against the benefits of increased competition. The remainder of this section focuses on the concepts of competition.

2.1.1 Perfect competition

Since the basic definition of market power implies a comparison with competitive outcomes, it is worth summarizing what is meant by this term. In a perfectly competitive market, no participant – whether it is a producer or a consumer – has the ability to change the market outcome through its own actions. While the market price is driven by the *aggregate* of consumption and production decisions, each individual participant is a price-taker. Under perfect competition, each producer needs only to decide how much of a good or service to provide given the prevailing market price. Since no one producer can change the market price, a logical implication of perfect competition is that producers enter into *all* sales for which the marginal cost of production is equal to or less than the market price of the good.

As in many other industries, producers of electricity face costs of production that exceed the short-run variable cost of producing an additional MW. These costs include non-variable O&M costs, salaries of plant staff, capital expenditures, maintaining an inventory of necessary parts, in addition to system charges, taxes, and the cost of the original investment. The presence of these costs can make total production costs exceed marginal costs for many producers.

For plants with relatively low production costs, there will be many periods in which they will run but not be the marginal producer. The resulting market price will exceed their own marginal costs and contribute towards recovery of total operating and capital costs. More expensive plants will operate less frequently, however, and at some point we might expect to find some plants that are the marginal producer whenever they operate. In this situation, receiving a price that recovers only short-run variable production costs will clearly fail to recover the total cost of such plants.

In properly functioning markets, this is not a problem. A producer who fails to cover costs above marginal costs will generally exit the market for the day or permanently, reducing available supply. To clear the market, prices rise to reduce demand. Note how the exit of the high-cost producer resulted in an increase in the market price. This implies that the next highest-cost producer now receives a price in excess of its own marginal cost.[1] Equilibrium occurs when the revenues earned from market prices in excess of marginal costs are sufficient to neither cause exit nor attract new investment.

A critical part of the equilibrium mechanism just described is the active role of consumers in determining the market price. As supply contracts due to insufficient revenues, consumers ‘compete’ for the supply that is left, which raises the price. It is through this mechanism that competitive markets are able to move towards an equilibrium state in which even the highest-cost producers recover more than their marginal costs in some hours.[2] An active supply and demand side will achieve a competitive equilibrium.

2.1.2 Deviating from perfect competition

Deviations from perfect competition may occur whenever the assumptions about impacting prices as noted above are not valid. Typically, individual production decisions

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1 Actually, the new market price will exceed the pre-exit market price, which was set at the marginal cost of the exiting producer. How much higher the post-exit price is depends on the steepness of the supply curve: the less price-sensitive consumers are, the more dramatic the price increase required to reduce demand and clear the market.

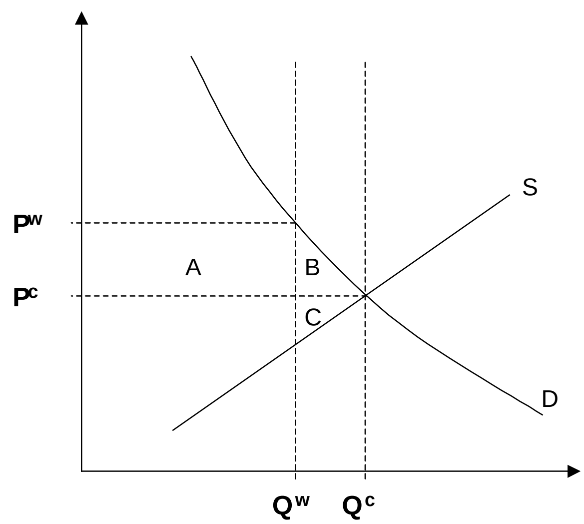
2 In hours when capacity is not limited, such as off-peak hours or during months of lower demand, no such rationing may be required, in which case prices will be driven down to the marginal cost of the last generating unit used.

will not change the market price if all producers are small. If a market participant is sufficiently large, however, its production decisions may actually move the market price. This can create a situation where it is actually profitable to produce less of a good, in order to raise the price received on other sales.

Figure 1 illustrates this scenario. The competitive outcome results in a quantity of Q^c and a market price of P^c. By reducing output to Q^w, however, the producer can raise the price to a higher level, P^w.

Figure 1: Rising Market Price by Withholding Output

Figure 1: Raising market price by withholding output



There are two major impacts of restricting output. First, the market price rises above competitive levels, indicating higher costs to consumers and greater profits to sellers. The first effect is simply a transfer of wealth from consumers to producers, represented as rectangle A in Figure 1. Second, the higher price may reduce demand, pricing some consumers out of the market and reducing the overall quantity that is supplied. The second effect represents the overall reduction in both production and consumption compared to the competitive outcome. This is referred to as "deadweight loss" and is represented by areas B and C in Figure 1.

In our illustration, this reduction of output is profitable if area C – the foregone profit from sales at the competitive price – is smaller than area A – the increased profits on remaining sales from raising the price. This requires that the costs represented by area C be borne by the same firm that benefits from the gains in area A.

In practice, withholding output by one producer will not necessarily reduce the total quantity supplied by all producers. More expensive generators that were out of merit at the competitive price will now be used to replace some or all of the withheld output. This will still raise the market price, even though the total quantity supplied may be the same.

In summary, while the perfect competition model is an idealization, a workably competitive market is necessary to ensure efficient outcomes and long-term sustainability of the market solution for electricity supply. The analysis of economic withholding in Alberta will be based on a **"competitive" threshold**, not compared to a perfectly competitive model.

2.1.3 "Economic" versus "physical" withholding

In the context of electricity markets, the terms "economic withholding" and "physical withholding" are widely used. Physical withholding refers to the practice of reducing the quantity of supply that is offered to the Power Pool, either through unavailability declarations, offer blocks that sum to less than the capacity actually available, or strategically reducing generation output relative to dispatch.

Economic withholding centers on the offer prices associated with each block of output. At one extreme, very high offer prices effectively remove capacity just as if that capacity had been declared unavailable. However, as noted above, not all market power strategies require that "withheld" plant not actually run.

Regardless of how it is actually accomplished, withholding supply requires that an alternative supplier or a higher priced block from the withholding supplier be used to replace the withheld quantity and accordingly, both economic and physical withholding imply an increase in the market clearing price. Alternatively, demand would need to be reduced by the withheld amount.

2.1.4 Economic withholding only a subset of market power pricing strategies

Prices can also be profitably influenced without changing the quantity supplied by generators, nor changing whom supplies it. If there are 'steps' in the offer prices submitted to the Power Pool, a generator may be able to increase its offer price without affecting its place in the merit order. For example, if a generator, Gen A initially submits an offer of $50/MWh, and the next highest offer is for $58/MWh, Gen A could have raised its offer price up to $57.99/MWh with no risk of not being dispatched. If Gen A is the marginal generator, it will be able to set the market price at this higher level.

Gen A may be able to raise its offer price higher still, particularly if the quantity offered at $58/MWh is relatively small. An offer above $58/MWh would entail a loss of output to Gen A, but perhaps not sufficiently large to offset the gains from the higher market price. The key to such strategies is for the offer price to be near the expected marginal unit. A generator that increases its offer from $10/MWh to $20/MWh while the price-setting unit offers $60/MWh will clearly have no impact on prices at all.

There is a broad spectrum of strategies available to all market participants, comprising of both quantity declarations and price offers. The two are analogous in terms of economic behavior, and there is no meaningful distinction between them. However, as rules and policies are developed to address specific behavior, it should be borne in mind that any price-based strategy would generally have a quantity-based analog. Policies that focus exclusively on either offer prices or quantities will tend simply to shift strategic behavior to the less-restricted bidding parameter.

2.1.5 Unilateral versus multilateral strategies

An additional level of complexity arises when considering the joint impact of two or more market participants. It is possible that two generators – each one individually unable to affect the market price profitably – may be jointly able to raise prices. While implementing such an outcome may take the form of an explicit arrangement, this is *prima facie* illegal. More often, joint action arises from two or more participants correctly anticipating the likely strategies of other participants; this is often referred to as "conscious parallelism" in the anti-trust context. When one airline lowers fares, for example, others may respond in kind. Similarly, as one hotel announces its pricing for the next season, it is only natural to expect other hotels to consider this information as they develop their own prices.

Markets rely on competitive responses to keep attempts to raise prices in check. If one generator increases its offer prices, the willingness of other generators to produce electricity at a lower price will reduce that generator's sales. At other times, however, competitors may anticipate that they will gain more from not undercutting another's offers, and the price increase may be sustained.

The sustainability of any price increase ultimately depends on whether the activity that raises prices is profitable to those who undertake it, and whether undermining that activity is profitable to those who could undermine it. If it costs more to raise market prices – in terms of lost sales, for example – than is gained in increased revenue, the price increase will not be pursued. Similarly, if the increased prices attract new suppliers, or if existing suppliers are able and willing to increase output, the high prices will be quickly undermined.

2.2 WHY IS MARKET POWER SUCH A KEY ISSUE IN ELECTRICITY MARKETS?

There are aspects of electricity markets that make market power issues more important than elsewhere. Some characteristics exacerbate the potential for market power, while others simply raise public sensitivity to the issue.

2.2.1 Supply function concepts

Recalling the example of a firm that can raise prices by restricting output - Figure 1 – we can make some general observations about the conditions that can make such withholding more or less profitable. Withholding is profitable if the costs of withholding, in terms of lost sales and profits (area C) are less than the increase in profits on the remaining quantity (area A). The relative sizes of these areas depend on three critical factors:

- The steepness of the demand curve, which determines how much prices will rise in response to a reduction in supply.
- The steepness of the supply curve, which determines how much profit is given up when output is reduced, as well as the cost of replacement power, which also determines the price response to withholding.
- The quantity of remaining sales that benefit from the higher prices. Naturally, if all sales must be sacrificed to raise prices, the strategy is not profitable.

These observations indicate that demand response, production cost characteristics, and composition of generating portfolios all affect whether withholding output can be profitable. Two of these factors – demand response and ownership concentration – can be directly affected by the efforts of policy makers.

2.2.2 Characteristics of electricity markets

The history of electricity markets – that of large regulated monopolies with unique service territories – creates legacies of market shares and concentrations that are often incompatible with competitive results. Many restructured electricity markets have required the divestiture of utilities' generation assets in order to create smaller, more numerous firms. In Alberta, operating control was fragmented through the design and sale of long-term contracts with unit-specific dispatch rights.

In most markets, the relative lack of significant[3] demand participation in real-time electricity markets increases the sensitivity of market prices to changes in supply. Without demand response, the only competitive pressure is exercised from alternative suppliers. In times of very high demand, there may be very few generators that are not already dispatched, reducing the number of effective competitors dramatically. In most markets, demand price response plays a more active part in determining the market price of a good. Electricity markets to date have had minimal demand participation, depriving the market of a vital restraint on market power.

Other factors affecting the profitability of withholding strategies include:

- ***Contractual position of generators***: To the extent that some output is 'pre-sold' under contracts, these sales cannot benefit from increasing spot prices.
- ***Uncertainty of demand***: The price response to withholding may vary depending on the level of load. If demand levels cannot be predicted accurately, producers face a higher risk of withholding either too little to be effective, or more than was necessary.
- ***Uncertainty of supply conditions***: Like demand uncertainty, if supply conditions are not known precisely, it is more difficult to determine the necessary level of withholding.

In general, incentives to raise prices in the spot market may be tempered by increased forward market liquidity and by careful consideration of what system information is made available in real-time.

For the purpose of this analysis, the Pool will continue to focus exercise of monopoly power by suppliers rather than on monopsony power by loads in general. Market power analysis in electricity markets usually focuses on supplier market power since very few loads have the ability to constrain their consumption strategically in order to control prices. Many distribution companies are incapable of strategically cutting off certain loads. Also, most loads are small relative to the system, making them less capable of impacting price to their benefit, and the benefits are much less profitable to the load.

[3] Significant demand response would be sufficient response in order to be able to effectively respond to a system contingency or change in offer behavior. A change in offer prices for an amount of generation that exceeds the amount of price responsive load has the potential to artificially raise the clearing price.

However, we do need to understand the magnitude of demand responsiveness as it directly impacts the profitability of attempts to raise the clearing price. Provided there exists sufficient price responsive loads, attempts by suppliers to raise the price beyond the competitive level will be "managed" by the market, since loads will respond by choosing not to consume. However if offer volumes (MWs) exceed the amount of price responsiveness in the market, the price could be artificially increased.

3 IMPACT OF WITHHOLDING IN ALBERTA

The impact of withholding in Alberta is a function of the ability for loads and suppliers to respond to the resulting price changes. Accordingly, the closer to the real-time delivery period that withholding occurs, the less able is the market to respond; and the greater the probability of success associated with the withholding exercise.[4]

Electricity markets experience volatility in pricing unlike other commodity markets. This volatility stems in large part from the inability to store electricity, requiring instantaneous matching of load with generation. When either demand or supply are relatively insensitive to price, significant price swings may be required to change consumption or production levels. In this section, we examine the broad indicators of competitiveness in Alberta's electricity market. These indicators or components in large part determine the potential for strategies designed to influence market prices.

It should be noted that this paper does not conduct a comprehensive evaluation of the competitiveness of Alberta's marketplace. The focus of this broad assessment is the need for market initiatives to manage possible economic withholding.

3.1 SUPPLY GROWTH AND RESPONSE

The Pool has witnessed continued growth in the number of Participants, from 59 to 190 over the past year. The majority of new Participants are either marketers or self-retailers. However there are some new Participants with generating assets.

The changing supply characteristics have been reflected in offer prices into the Pool. In the first half of 2001, the supply curve was characterized by two pronounced 'steps'. These steps occurred at around $10/MWh, with the second at approximately $100/MWh. This was the result of publicly known offer strategies for the Balancing Pool's coal and gas generating assets. Between $10/MWh and $100/MWh, supply was highly inelastic especially above $100. In early 2001, high natural gas prices increased generating costs for gas-fired power plants. The price of imports was high, exacerbated by the California crisis, prolonged drought conditions and lower availability of hydro production in the Pacific Northwest. Furthermore, supply offer behavior in Alberta was influenced by the public disclosure of the offer strategy for Clover Bar, a key marginal producer whose PPA is currently held by the Balancing Pool.

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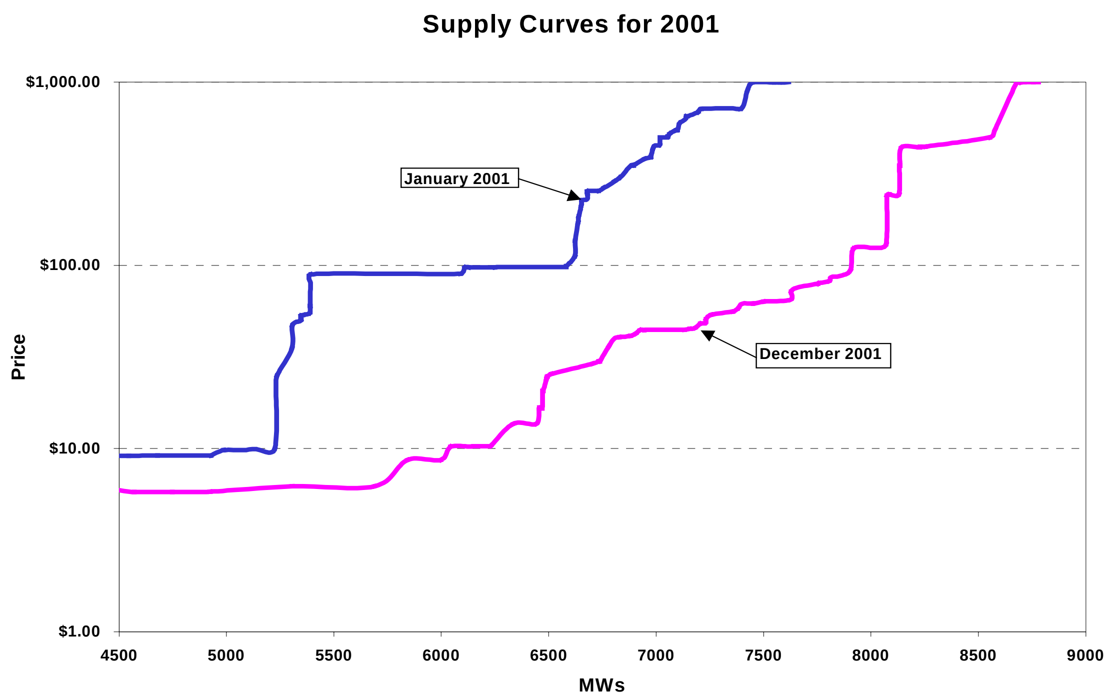
4 Since electricity cannot be easily stored, all withholding in a technical sense must occur in real-time. However, changes in offer strategies that occur earlier still allow other participants greater scope to expand their supply, reducing the profitability of any eventual withholding. Thus, changes in offers at the last minute, when competing suppliers have not developed expectations of prices that would give them incentives to have resources available, are still more likely to affect market prices profitably.

Due to the inelastic nature of some sections of the supply curve, small increases in demand resulted in large increases in Pool Price. Often the intersection of supply and demand would occur at the 'bottom of the cliff,' requiring only a small increase in demand – or a small contraction in supply – to sharply raise prices.

Figure 2: Supply Curves for 2001



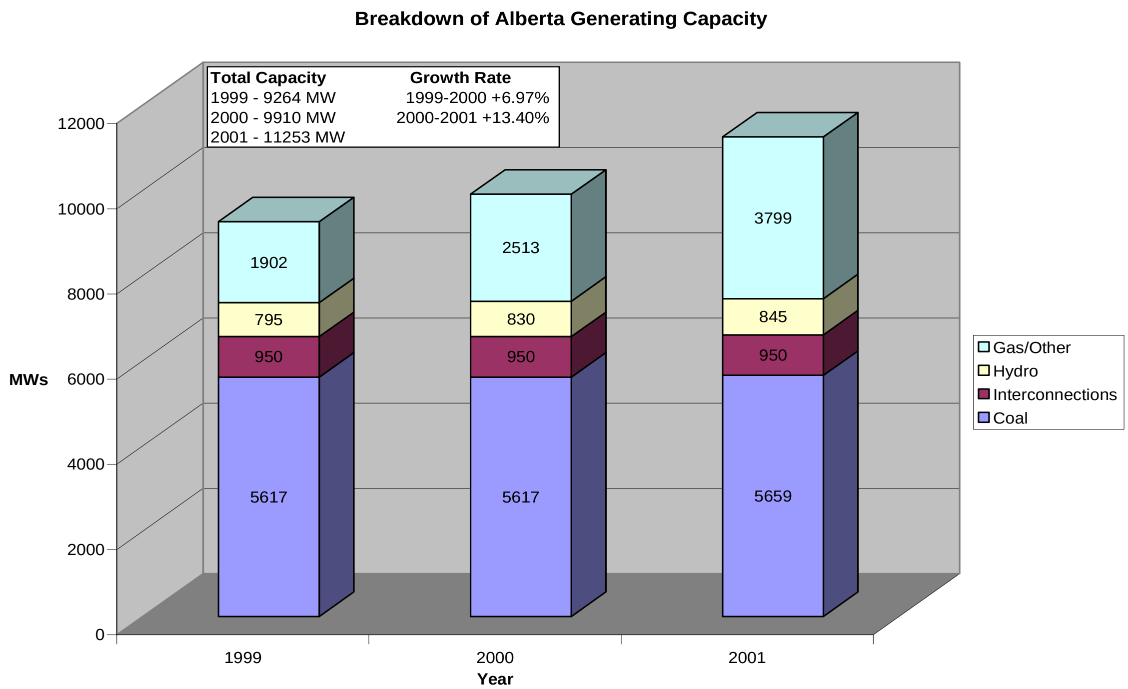
These two supply curves from January and December 2001 illustrate how the market has evolved. The curve has flattened due to the reduction in gas prices, entry by new and more efficient gas-generation with lower heat rates, and increased competition among Participants. The long flat segments have also been diminished as a result of the reduced dominance of the Balancing Pool's offer strategy. Also note that the December 2001 supply curve, like the one from January, includes offers from imports.[5] The value of electric energy throughout the Western Interconnection dropped over the course of the year, with the result that import energy is available at much lower prices contributing to the increased elasticity of the supply curve over 2001.

While the supply curve has flattened, it has also shifted outward to the right. This has been the result of significant new additions of generating capacity in Alberta. In 2001, Alberta added roughly 1300 MW of additional capacity, mostly gas generation. As demonstrated in the graphic below, these additions were part of a continuing trend. Capacity has grown from 9,264 MW in 1999 to 11,253 MW in 2001. This represents an

5 Since launching the intra-day market (IDM), import or export transactions are simply scheduled in real-time as zero-price supply or load.

annual growth rate of roughly 7% in 2000 and 13% in 2001. Interconnection capacity is unchanged, and there has been small growth in hydro and coal generation. This resulted in the supply curve shifting farther to the right. The following graphic demonstrates the growth capacity over the past 3 years at a greater rate than growth in demand (including exports).

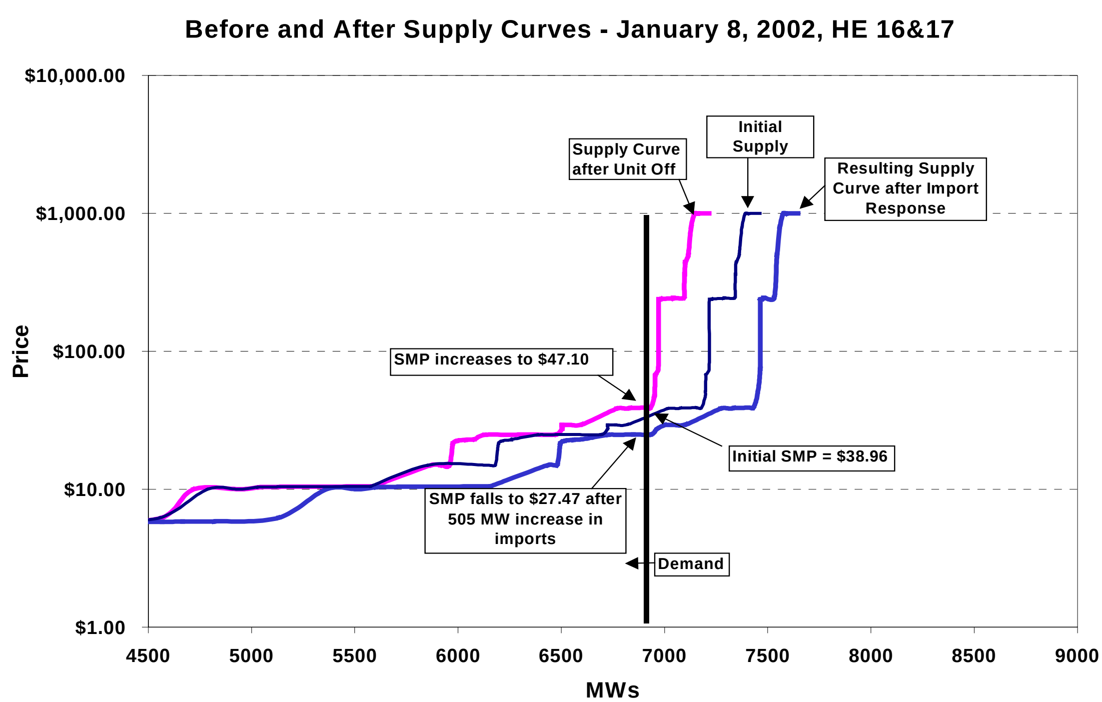
Figure 3: Breakdown of Alberta Generating Capacity



The growth in new generation relative to the growth in demand has resulted in a significant increase in the efficiency of the supply side in responding to periods of scarcity in the Alberta Market. The following graph demonstrates before and after supply curves for the afternoon of January 8, 2002. The initial supply curve for HE 16 is shown in the middle. During HE 16, a 350 MW unit was forced off-line. As a result, the supply curve for the hour shifted back by 350 MW, as shown in the graphic below. Consequently, the SMP increased from $38.96 to $47.10.

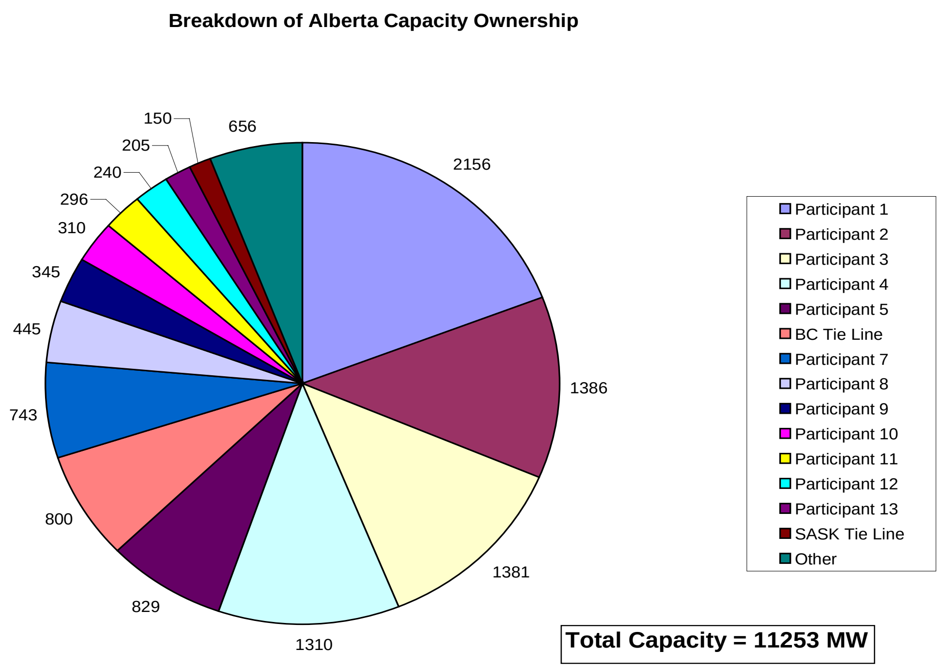
However, importers quickly responded to the unit outage. The import schedule increased from 70 MW in HE 16 to 575 MW in HE 17, an increase of 505 MW. This more than offset the 350 MW loss of generation. As a result, the supply curve for HE 17 actually shifted further right than the original HE 16 supply curve. As a result, the SMP fell to $27.47, lower than the SMP prior to the unit outage.

Figure 4: Before and After Supply Curves – January 8, 2002, HE 16&17



A further indicator of supply competitiveness is the concentration of supply among Participants. Figure 5 below shows the current distribution of supply among supplier companies. Again, this paper is not a comprehensive analysis of the potential for market power including an analysis of holding restrictions (that analysis has been completed elsewhere through the London Economics work for the Balancing Pool and Department of Energy during the PPA Auctions and subsequent Market Achievement Plan market offerings). However, a market with many sellers as illustrated by the supply distribution graphic, has a better potential for competitive offers and prices.

Figure 5: Breakdown of Alberta Capacity Ownership



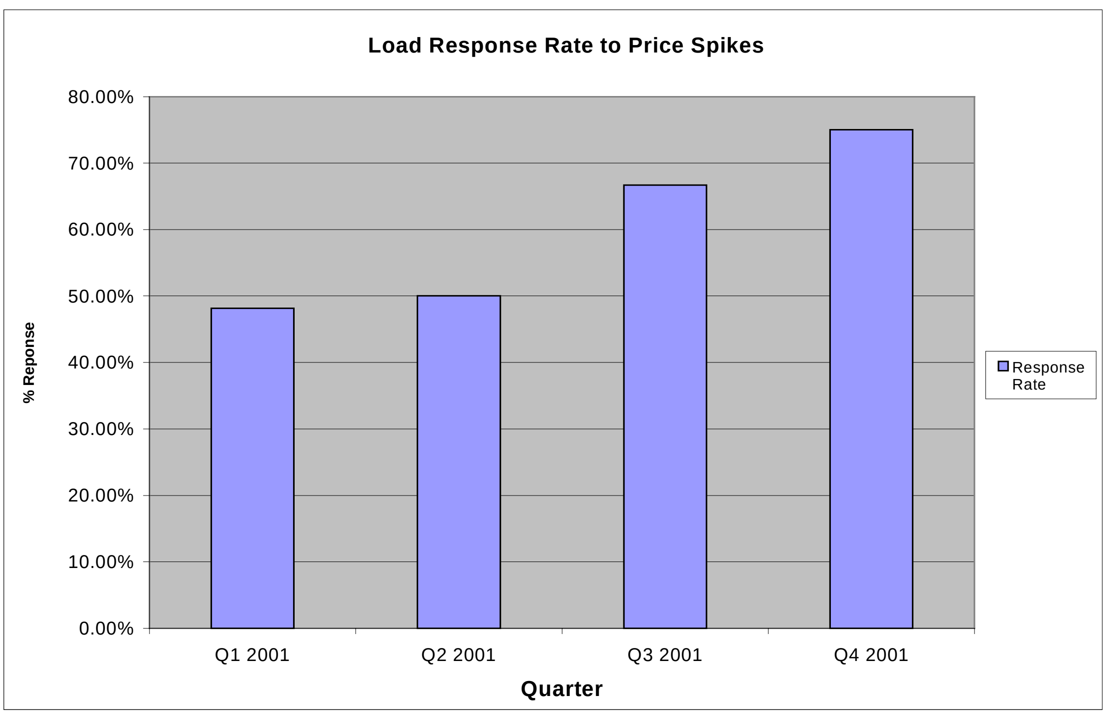
3.2 LOAD RESPONSE

Load response in a market reduces the need to mitigate offer behaviour through rules including maintaining a price cap. The justification for price caps is typically to set a proxy price to represent the price at which load would rather be shed than consumed. If consumers are able to make a purchase decision based on knowledge of price and delivery details directly in the marketplace, as is the case for most other traded goods, the justification for a price cap rapidly disappears.

Demand response is naturally limited primarily by a lack of exposure to Pool Price by many electricity consumers in real-time. This makes many consumers of electricity, particularly residential and small commercial loads, relatively unresponsive to price changes in real time. By contrast, many major industrial consumers are exposed to real-time pool prices, and have a financial incentive to modify their electricity consumption in response to price changes. Industrials can maximize their profitability by consuming when prices are lower, and by curtailing consumption when prices are high.

Prior to 2001, loads were mainly insulated from Pool Price exposure through a system of legislative hedges; price responsive load grew in 2001. Initially in 2001, Alberta system load appeared relatively unaffected by price spikes, with small and sporadic demand response to price increases.[6] As 2001 progressed, however, there was a steady increase in the amount of demand responsiveness. A pattern of load responsiveness to price became evident towards the end of February and beginning of March. The following chart demonstrates the percentage of price spikes where the load responded.

Figure 6: Load Response Rate to Price Spikes

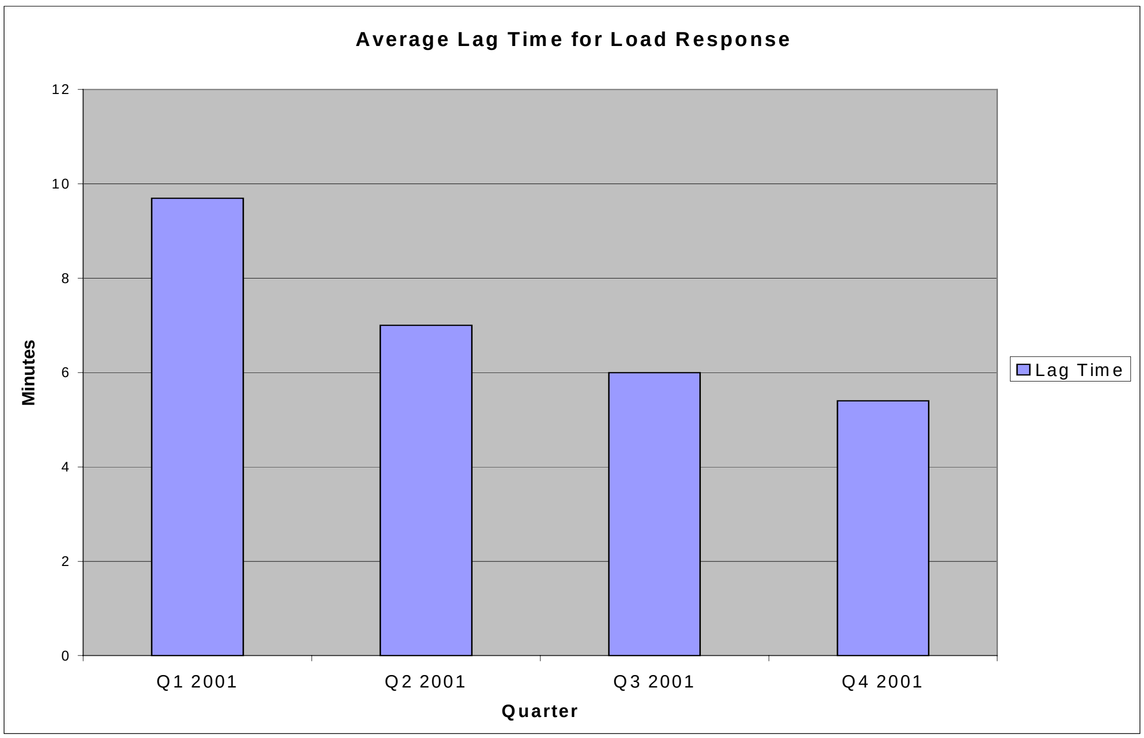


6 For the purposes of this analysis, a price spike has been defined as a $100 increase in Pool price in less than 30 minutes, and where the initial price was less than $200 and the ending price was greater than $200.

Load responded to fewer than half of all price spikes in the first quarter of 2001. By the fourth quarter, nearly 75% of all price spikes resulted in a demand side response of varying magnitude.

Major industrial loads are not only responding to price spikes, but are responding quicker than before. In the first quarter of 2001, for price spikes where there was a demand response, the average lag time from when the price spiked to when the load began dropping was almost 10 minutes. In the fourth quarter of 2001, that lag time had dropped to just over 5 minutes. In the first two months of 2002, the average response time has dropped to 3 minutes, and some response is starting to occur prior to price changes (i.e., in response to forecast Pool price increases).

Figure 7: Average Lag Time for Load Response



The following charts illustrate a few examples of Alberta system load responding to increases in the SMP (system marginal price). The most dramatic load response to date occurred on the morning of October 22, 2001. A sharp price increase to $998 resulted in a 287 MW reduction in system load, at a time when the load is normally flat after the morning ramp. Figure 9 visualizes the extent of the above load response by contrasting the load for October 22, with the load of October 24, 2001, a comparable day where no price spike occurred.

Figure 8: Load vs. SMP – Oct. 22, 2001

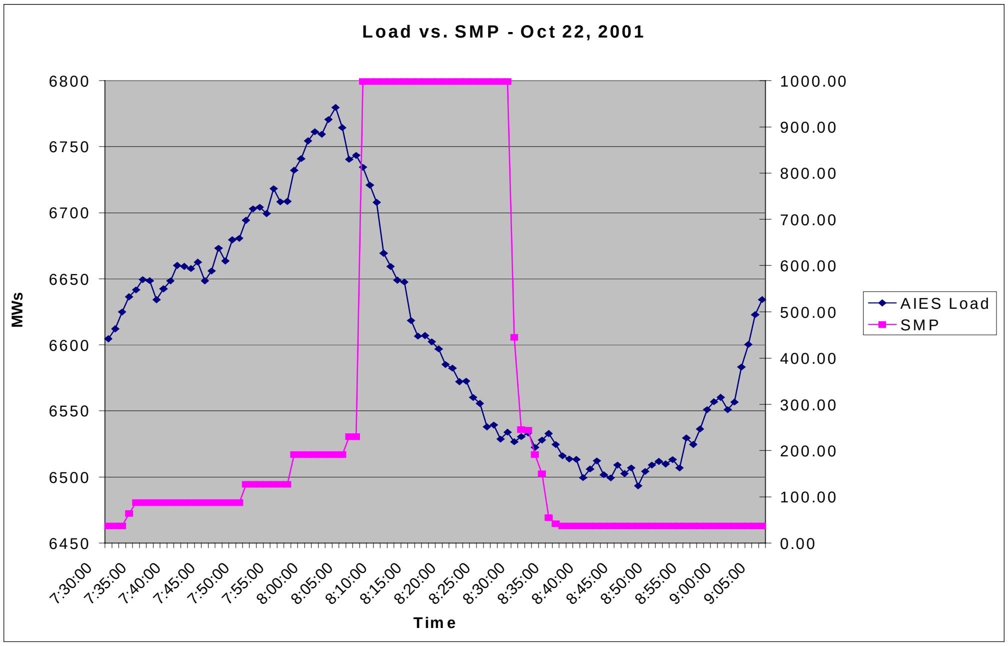
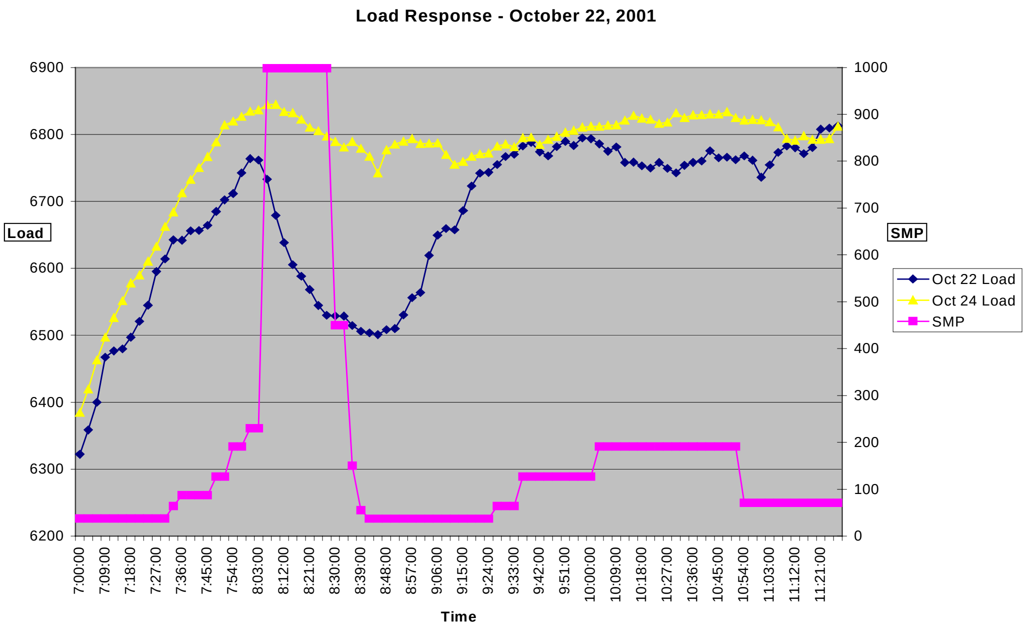


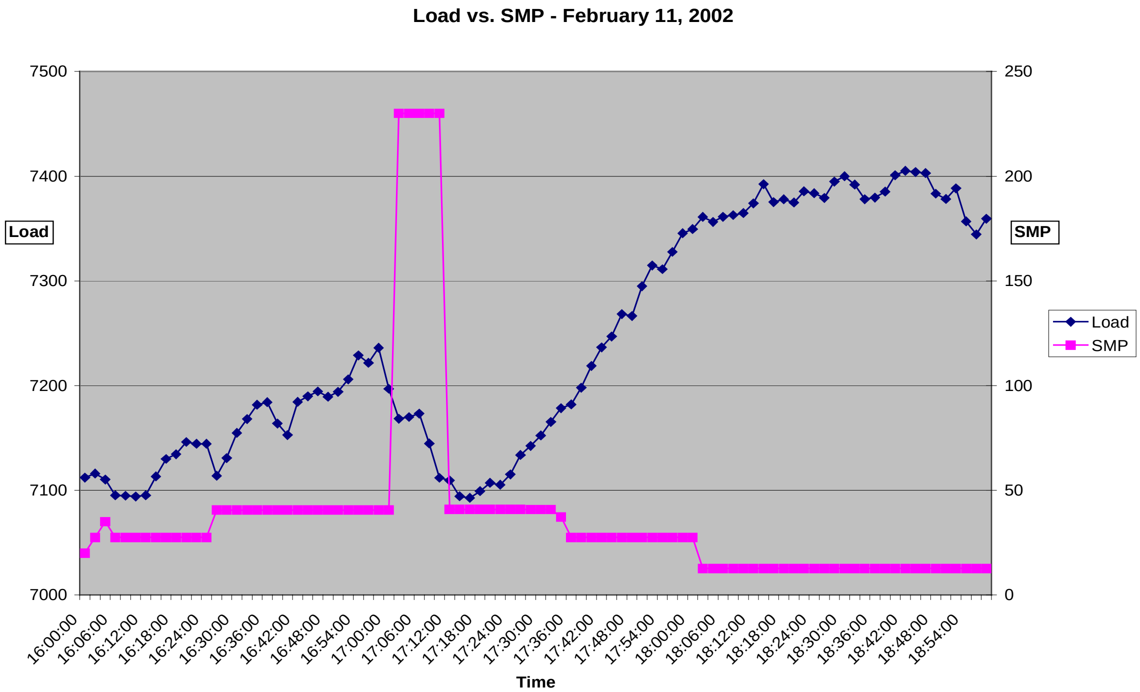
Figure 9: Load Response – October 22, 2001



More recently on January 10, 2002 a price increase to $120/MWh resulted in a 140 MW load reduction in just 8 minutes. The load began dropping within 3 minutes of the price increase. This vividly illustrates how the price thresholds for load sensitivity have dropped significantly. Evidence now indicates that significant price responsiveness exists as low as 70 to 80 dollars.

The following graphic for February 11, 2002 demonstrates not only load response to price, but also load response to 'forecast' price. The load in Alberta frequently drops in response to an increase in the real time forecast Pool Price. This can be seen in the following chart.

Figure 10: Load vs. SMP – February 11, 2002



In the above case, at 16:45 the System Controller increased the real time forecast pool price to $230 for the subsequent hour. The load began dropping prior to any increase in SMP. The load fell by 66 MW in 6 minutes in response to the forecast price for HE 18. Once SMP increased to $230, the load fell an additional 85 MW for a total reduction of 151 MW. This occurred at a time when load would ordinarily be increasing. As a result of the load response, the price spike lasted just 10 minutes. As a result of a pre-emptive load response to the real time forecast Pool Price, many forecast price spikes either never materialize, or persist for a very short duration.

The above examples illustrate a few incidents where the load responded quickly to jumps in SMP. It is also important to note that the magnitude of price response has increased throughout the year. In the first half of the year 2001, the average load response was about 100 MW. However, in the last quarter of 2001, average load response was almost 160 MW. However, depending on the magnitude of the price spike the load response can be as large as 300 MW.

The duration of price spikes declined considerably over 2001. In the first half of the year, the average price spike lasted for almost 70 minutes. However, in the last half of 2001, the average price spike lasted for just over 37 minutes. The reduced duration of price spikes is due in large part to the growth in price responsive load. The reduction in load following a price spike results in the price declining as the system controller dispatches down the merit order. Also, the faster response time for price responsive load has contributed to the shortening of the duration of price spikes.

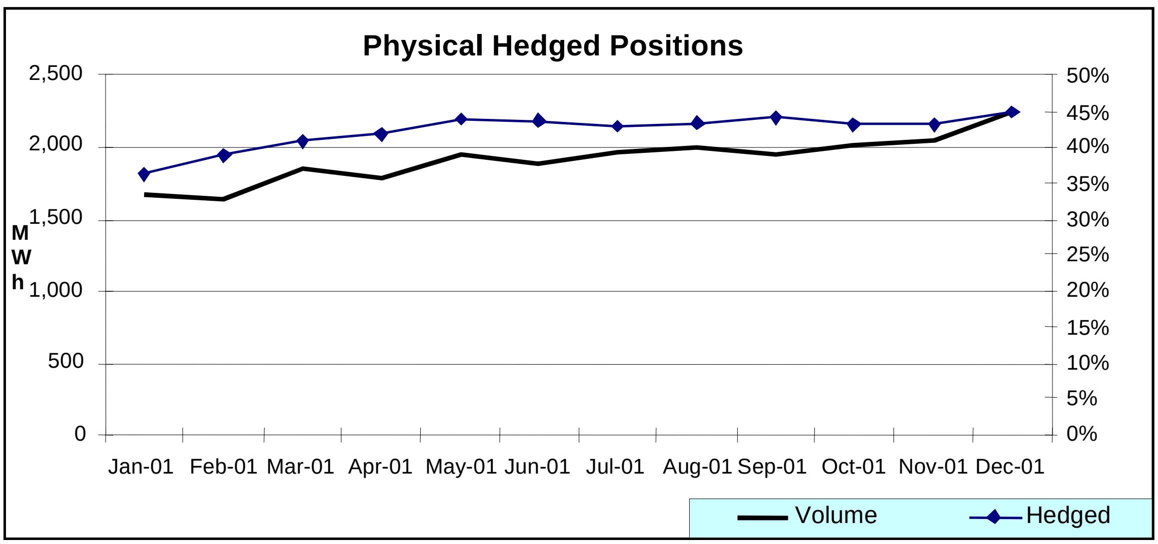
In summary, the increased responsiveness (elasticity) of demand to price has contributed greatly to the reduction in the frequency, magnitude, and duration of price spikes. Also, the load responsiveness to forecast prices has prevented many forecasted price spikes from occurring.

3.3 MARKET EXPOSURE TO POOL PRICE

A key component of a competitive electricity market is the ability for Participants to build a portfolio of purchases and sales reflecting their risk preferences and their energy needs. The forward markets provide such choices to both consumers and suppliers, allowing them to increase price certainty for some or all of their projected sales or purchases.

In Alberta's market, almost half of the energy delivered and consumed in 2001 was hedged with a physical contract and registered for net-settlement at the Pool. Financial contracts are also traded. Suppliers with a forward obligation have the incentive to meet these obligations by delivering energy, especially when Pool Price is rising. Load customers have the opportunity to re-sell the energy they purchased forward by not consuming during times of high Pool Prices. Through forward contracting, the financial incentives for raising or lowering Pool Prices are no longer split simply between generators and consumers. Instead, it is split between those who have a net obligation to deliver power and those with a need to purchase additional electricity in the spot market beyond what they have purchased in the forward market.[7]

Figure 11: Physical Hedged Positions



The existence of forward market and over-the-counter opportunities and the fact that the market during 2001 traded up to 50% of their supply and demand portfolio forward, indicates that only the remaining amount is exposed to RT Pool Price.

[7] A consumer that has pre-purchased 100 MW in the forward market may, in response to high real-time Pool Prices, elect to consume only 70 MW. The remaining 30 MW is settled at the Pool Price, making the consumer a beneficiary of the high prices. Conversely, a 300 MW may have already pre-sold its entire output in the forward market, making it indifferent to Pool Prices. If it suffers an outage, however, it benefits from a low Pool Price, as it must purchase replacement energy to fulfill its obligation.

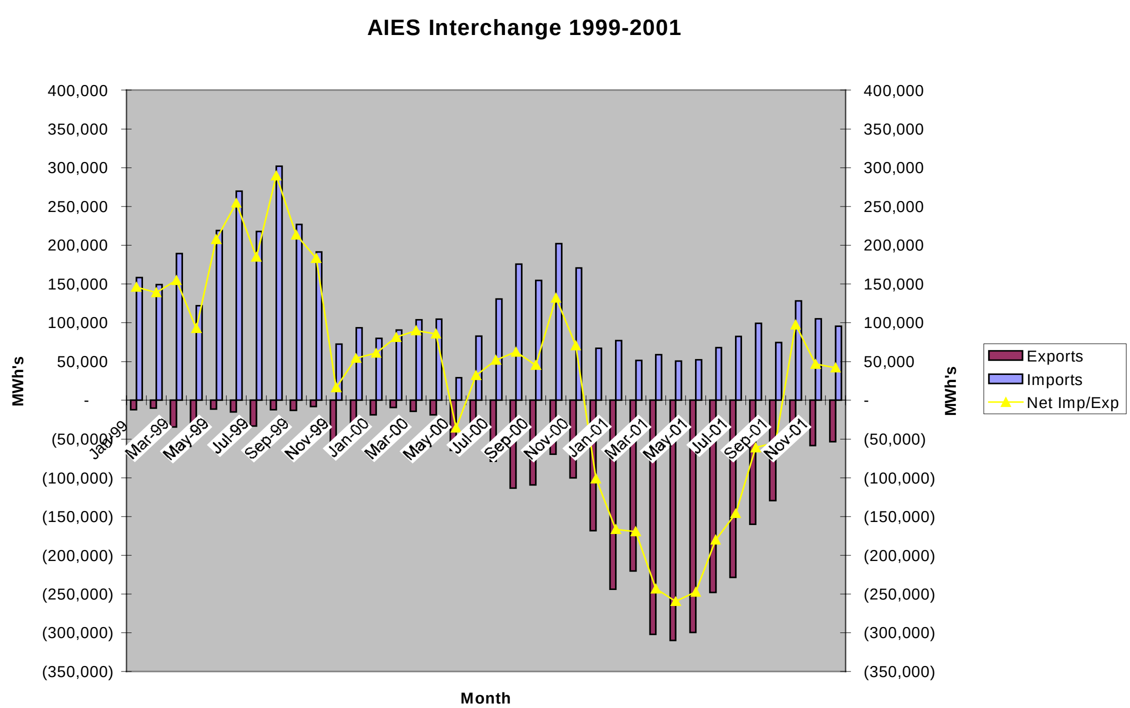
3.4 TRANSMISSION ACCESS

Transmission affects the energy market when access is restricted or constrained, whether through administrative restrictions - where use of transmission capacity is limited through ownership rights - or through physical congestion where there is insufficient transmission capacity to support the economic dispatch of generation.

Ease and availability of transmission access for inter-regional trade is dictated by the terms and conditions of the tariffs of the various transmission providers between the source and sink. That ease and availability is dictated by the lowest common denominator of the various tariffs. While there continue to be concerns about access through adjacent jurisdictions to/from external markets, the volume of energy transacted on the interconnections has increased substantially over the last couple of years (see the following graphic) as more players acquire the expertise needed to participate in interchange transactions and take advantage of the basis spread between the energy markets in Alberta and its neighbouring regions.

To date, transmission congestion within Alberta has not been a major factor in the energy market. With the increase in both the load and installed generation capacity in Alberta, transmission congestion will become more of a factor in the energy market if "out of merit" generation must be dispatched more frequently to compensate for the congestion.

Figure 12: AIES Interchange 1999-2001



3.5 OFFER RESTATEMENTS

Offer restatements in RT or close to RT can have a substantial impact on the market. Under normal operating conditions, the majority of unused but available capacity in the market near to the delivery hour is interconnection capacity. There frequently exists more import capacity than incremental Alberta generation due to start up constraints with idle Alberta generation. The evidence indicates that interchange is very responsive to price changes, with imports falling in response to low prices and increasing following price increases.

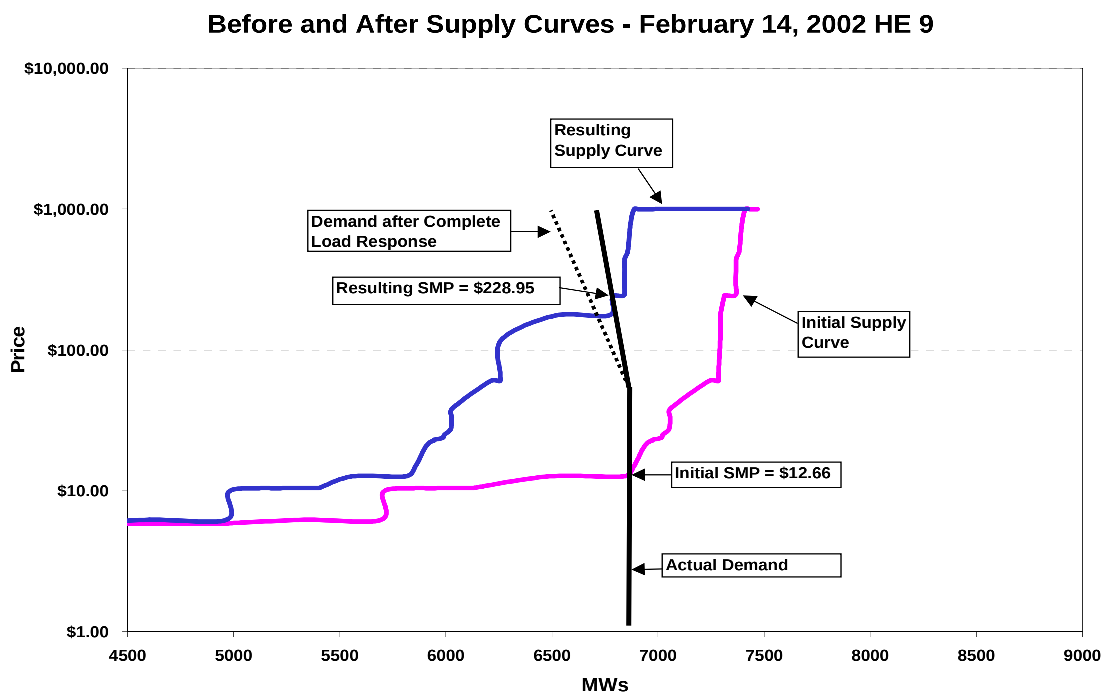
However, interchange schedules are fixed for the hour, making imports incapable of responding to intra-hour market occurrences. As a result, an intra-hour import response is not possible to any use of restatements by Alberta suppliers in RT.

Although electricity demand is generally fairly inelastic, Alberta has however witnessed significant growth in price responsive load. There currently exists roughly 300 MW of price responsive load in Alberta. However, given that many suppliers control more than 300 MW, the potential exists that a restatement in excess of 300 MW could result in an arbitrarily high clearing price, given that remaining loads are incapable of responding or choose not to respond.[8] Such a restatement would amount to withholding, and has the potential to cause a considerable impact to the clearing price.

8 Such withholding, however, might not be profitable, and hence not a credible strategy for a supplier. The more responsive load is to price, in general, the greater the output loss to the withholding supplier. At some point, the price impact on profits may be outweighed by the quantity loss.

Figure 13 shows an example of the market impact of restatements within the hour wherein the resulting Pool Price increased from $12.66 to $228.95 with a restatement of energy of 924 MW to a higher priced block.

Figure 13: Before and After Supply Curves – February 14, 2002, HE9

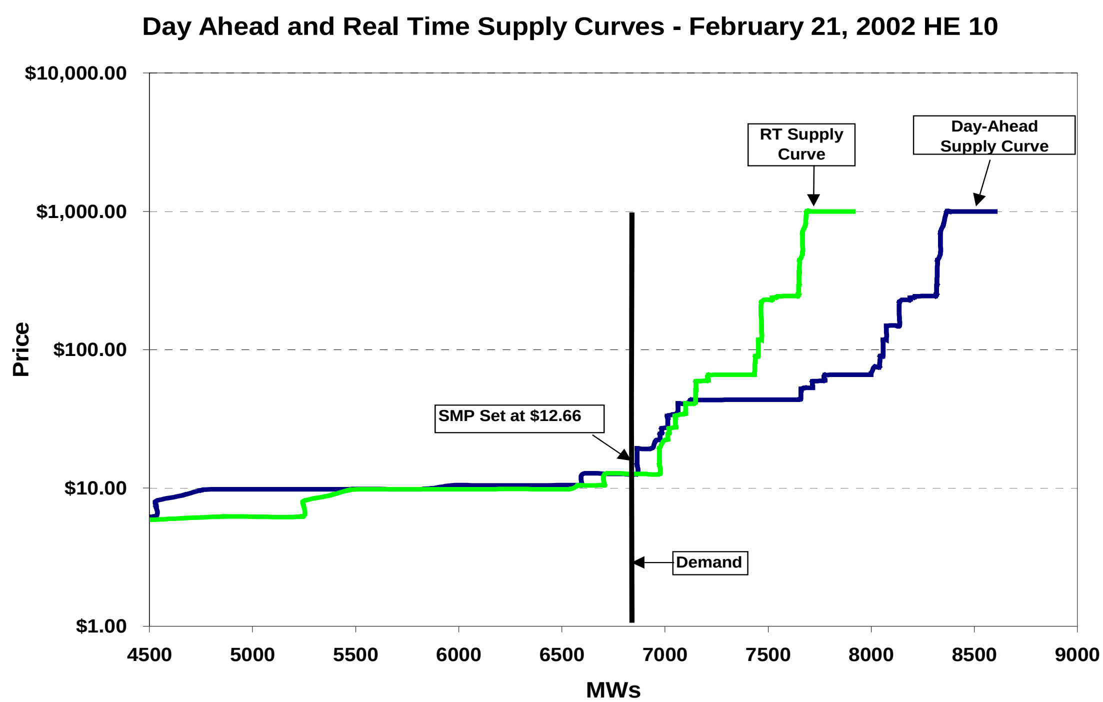


Restatements also occur before the RT delivery hours, though the impact to the marketplace is quite different. The following chart shows two supply curves for HE 10 of February 21, 2002. The supply curve generated from the day ahead offers is compared to the actual real-time supply curve reflecting the actual supply that was made available in real-time including the impact of all energy restatements made between the day-ahead offers and real-time.

As seen below, the supply curve shifted sharply to the left. This represents offers being removed for generating assets that are not economic to run compared to forecast Pool Price. For the most part, these generating assets are gas units that cannot economically compete in the current price environment, and as a result, their capacity is made unavailable. The shift in the supply curve also represents energy restatements due to reserve obligations. Generating assets dispatched to provide operating reserve would reduce their offers into the energy market such that they can provide their reserve obligations.

While day ahead restatements will have an impact on the market through changes in forecast Pool Price and marginal units, the market is better able to respond to these changes.

Figure 14: Day Ahead and Real Time Supply Curves – February 21, 2002, HE 10



3.6 CONCLUSIONS ON ALBERTA MARKET COMPETITIVENESS

The basic conditions for a competitive market have largely been realized. This stems from a variety of factors:

- Concentration of incumbent generation has been lessened through the PPA auction and new entry;
- Diversity of suppliers continues to increase with new plant development.
- Demand response appears to be increasing, limiting the occurrence and duration of price spikes (though still small in comparison to supply's ability to change).
- The interconnections integrate Alberta with the broader Northwest markets, introducing import-competitors when market price is attractive and export-consumers when the market price elsewhere is more attractive.
- Forward markets are available for portfolio management. The existence of forward markets reduce the reliance on spot market and alter incentives to manipulate real-time prices.

The following table summarizes the snapshot evaluation of the Alberta electricity market.

Table 1: Snapshot Evaluation – Alberta Electricity Market

Competitiveness Attribute	Rating	Comment
Market concentration	Good	PPA auction and new entry have reduced concentration
Supply growth/entry	Good	21% supply growth over 2 years New capacity planned
Load responsiveness	Good	Higher than most power markets Response to 75% of spikes
Exposure to Pool Price	Moderate	Just under 50% known hedged Developing forward markets
Transmission markets	Moderate	Increased transmission flows Access issues remained

The issue in the market lies in the limited periods of time when the market is less able to respond to changes – i.e., in the real-time delivery timeframe. During this short period of time, some suppliers can respond though many have already dispatched or have made day ahead decisions to remain off-line. Additionally, loads that mainly face an ex post price have limited ability to respond.

While we are of the opinion that the market is mainly operating competitively, it is critical that the Pool continue to monitor the market performance, ensure that prices are available to the market for response, and make any necessary rules changes to enhance the competitive environment.

4 MEASURING MARKET POWER *EX POST* IN ELECTRICITY MARKETS

The measurement of market power is of great interest in restructured electricity markets. It is a challenge to distinguish between spikes caused by scarcity as opposed to those caused by market power. The central question is how to determine if prices are workably competitive. The answer to this question is of significant importance, as a finding that prices are not competitive may be a precursor in many jurisdictions to refund proceedings, sanctions, or other mitigating action.

4.1 ARE HIGH PRICES ALONE EVIDENCE OF MARKET POWER?

Price spikes tend to invite much suspicion regarding whether such prices are appropriate. There are several reasons why high prices may be expected. At the very least, some price spikes may be less egregious than may be claimed.

Most directly, high electricity prices may reflect high input costs such as the spot price of fuel. Even if fuel is not actually purchased on the spot market, the spot price represents the value of using the fuel for electricity production at the time that decision is made.

Other costs may arise as a direct result of output decisions, though they may be harder to quantify. These include the increased cost of equipment degradation if used outside of designated parameters, for example, or the acceleration of major maintenance of a unit.

If generating electricity requires foregoing other opportunities, these foregone costs will appropriately be included in a generator's bids. Such opportunity costs are particularly important for hydro plants with storage capacity. Generating in any given hour precludes generation in a future hour if storage is not possible. The value of the most profitable alternative is a proper part of marginal costs. The opportunity cost argument also impacts on export decisions. If the price in external markets rise, clearing prices in Alberta rise as well; alternatively, suppliers choose to export and prices rise anyway because supply is not dedicated to Alberta.

Finally, it is possible that electricity prices will be determined in many hours as much by demand-side bids as by generators' offers. The cost of reducing load has little to do with the cost of producing electricity. Instead, demand-side bids will be driven by the cost of avoiding consumption. This can entail reduced industrial production, investment in energy-efficient technology, or simply a reduction in convenience.

High prices are not, in and of themselves, indications of market power. The challenge is therefore to develop meaningful analyses that can discriminate between high prices resulting from genuine scarcity as opposed to the exercise of market power.

4.2 OVERVIEW OF POTENTIAL ECONOMIC APPROACHES

There are several approaches one might take to evaluate whether market prices are competitive. This section outlines approaches used in other jurisdictions which are mainly cost-based in nature.

A cost based approach is of limited value for the Alberta market given the difficulty in determining a suppliers' true operating costs. Further, a cost based approach is inconsistent with the 'market competitiveness' approach suggested as an appropriate threshold for monitoring and mitigation. In a competitive market, the long-run price should roughly reflect operating and opportunity costs, including the ability to sell into ancillary services markets and other geographic markets. Nevertheless, a theoretical overview of some cost-based techniques used in other competitive markets is provided below.

4.2.1 Lerner Indices – direct comparisons to marginal cost

The Lerner Index is a simple measure of whether market prices exceed marginal costs. The Index takes the form:

$$\frac{\text{Price - Marginal Cost}}{\text{Price}}$$

A perfectly competitive market is presumed to offer no margin above marginal cost, and hence the Lerner Index is zero. As price becomes much larger than marginal cost – as would be expected with extreme market power – the Index approaches a value of 1. While the Lerner Index is simple in concept, it is rarely used in the broader antitrust context due to numerous theoretical and practical difficulties.

Note that, in this context of the clearing Power Pool Real Time market, marginal cost refers to the marginal cost of the marginal producer, not to the individual marginal costs of all producers. A variation of this approach is to compare individual offers with the marginal cost of the producer submitting the bid.

This type of approach relies heavily on developing models of marginal production costs at the plant level. Recent experience in using such models to calculate competitive prices has proven highly contentious in principle and unmanageable in practice.[9] Some of the major points of contention include:

- Marginal costs ignore commitment decisions, which require the expectation that start costs and no-load costs will be recovered.
- The marginal cost of a unit is highly dependent on its current state: operating versus cold, fully loaded versus part-loaded, and how long it has been on or off.

9 The issue of refunds in California during October 2000 through June 2001 is still before FERC. Refunds are to be calculated against a competitive price based on the marginal cost of the last unit dispatched. Despite the volumes of data that has been collected in this proceeding, the methodology has been grossly simplified to facilitate implementation, though FERC acknowledges some of these simplifications contravene established economic principles.

- Non-fuel marginal costs, including opportunity costs of hydro plants, emissions permits, and accelerated maintenance requirements are very difficult to capture on an hourly basis.
- Given that marginal costs may increase or decrease with output, but offers into the Power Pool of Alberta must be strictly increasing in quantity, direct comparisons of offers and estimates of marginal costs may be difficult or inappropriate.
- Even in a perfectly competitive market, prices can exceed the marginal cost of producers if supply is constrained. The appropriate measure becomes the marginal utility of demand. Calculating marginal utility functions for consumers, if these are not reflected directly in market behaviors, is likely to be even more intractable than calculating marginal costs for producers.

4.2.2 Bid / Offer screens

An alternative to comparing bids[10] against estimates of marginal costs is to compare bids against previous bids submitted by the same plant. Variations in bids are to be expected given changes in fuel costs, for example.[11] Nevertheless, screening tools can be used to identify changes in offer prices or quantities that fall outside of established thresholds. To be effective, thresholds must be reasonably designed to reflect a range of cost-reflective offers. An offer that falls outside these thresholds may indicate a strategy driven by factors other than a change in underlying costs, including attempts to influence market prices.

Most bid screen formulations include the following elements:

- Determination of reference bids based on accepted bids when the market was assessed to be competitive;
- Adjustment of these bids if necessary, by indexation of fuel and other costs, etc.; and
- Some other methods for determining reference bids for plants that are rarely in merit, such as peakers.

4.2.3 Long Run Cost Measures

This category of metrics looks at prices over longer time horizons, and focuses on market prices rather than participants' offers. Using generic but reliable information on the major cost elements of power plant operations, the market can be characterized in terms of the dynamic conditions expected to prevail. These conditions are broadly classified as:

- **Market exit**: market prices are too low to sustain the existing set of investments, and one or more participants are expected to take generation off-line. Market prices are below the long-run average cost (LRAC) of one or more plants, and therefore are insufficient to recover going-forward fixed costs.
- **Market entry**: market prices are sufficient to stimulate new investment. New investment may include plant re-powering, life extension to existing units, expansion

[10] Many markets in the U.S. refer to supply offers as "bids".
[11] A bid screening approach based on previously accepted bids would therefore need to include indexation against fuel costs, emissions costs and other observable input prices.

of existing plants, or the development of entirely new facilities. Market prices are expected to be higher than the long-run marginal cost (LRMC) of expanding system capacity for some periods, but if prices stay above LRMC for substantial periods and entry is not stimulated this may be evidence of barriers to entry that may prevent competition from being effective at bringing down prices over time.

The information necessary to develop reasonable benchmark prices is not extensive, and adequate estimates can be developed from public or commercially available sources. Databases of existing plant costs are available, allowing generic cost models to be developed for plants of different age, technology, or size. Additionally, the auction of the Power Purchase Arrangements disclosed specific information for a large fraction of Alberta's generating plants.

In practice, the pattern of market prices over an extended period can be compared to the benchmark prices calculated for each of the market 'states' introduced above. If actual entry or exit activity is different than what these benchmarks would indicate, and if this divergence persists, it may be an indication that the market is not behaving competitively in a dynamic sense.

A drawback to this approach is that dynamic decisions such as plant retirement or development are based on expectations of market prices, not necessarily on current prices. A visible and liquid forward market would be a better comparison with the benchmark estimates. Otherwise, the most that can be said is that the recent history of prices *should have* resulted in certain entry or exit activity. Whether it did may be due as much to expectations being wrong as to uncompetitive behavior.

5 MITIGATION OPTIONS AND REGULATORY POLICY

Regulation and competition are substitutes. Where competitive forces can be relied on in markets to produce efficient and acceptable outcomes, there is minimal need for regulatory intervention. Where competitive forces are likely to be insufficient, the scope for efficiency-improving intervention rises.

5.1 COSTS AND BENEFITS FRAMEWORK FOR MARKET INTERVENTION

It is axiomatic that the total benefits of regulatory intervention, such as the mitigation of the effects of economic withholding, should exceed the total costs of doing so. From an efficiency perspective, cost-benefit analysis will typically look only at total benefits and costs, and not to whom these benefits and costs accrue. If equity considerations also enter into regulatory objectives, a balance will need to be struck between pure efficiency and equity objectives.

5.1.1 Benefits of regulatory intervention

If market outcomes are being distorted through the exercise of market power through economic withholding, there may be benefits to regulatory intervention. These include:

- ***Improvements to short-term market price signals:*** A targeted intervention may be welfare-improving if price outcomes are distorted. For example, if the true cost of electricity production in an hour is \$50/MWh, and a consumer is willing to pay up to \$100/MWh, then consumption is efficient. If the market becomes so distorted that the price is $500/MWh, then this efficient consumption will not occur. Where markets are truly not competitive (e.g. monopoly or oligopoly) then controls on pricing behavior may improve market efficiency.

- ***Prevention of wealth transfers:*** Although load in Alberta is more price responsive than in many markets, over the short-run the elasticity of demand with respect to price overall is still relatively low. The ability to cause a high and prolonged spike in electricity prices therefore could produce substantial transfers of wealth between consumers and suppliers. Since equity, and not just efficiency, is also a reasonable objective of regulatory action, regulatory policy may rightly judge that regulatory costs are justified.

5.1.2 Costs of regulatory intervention

Regulation is never costless, and the costs are both direct and indirect:

- ***Direct regulatory costs:*** Substantive intervention in electricity markets leads to significant regulatory costs. As the examples of California, New York and New England presented in the Appendix demonstrate, trying to constrain supplier market power within a limited range may imply the need to determine marginal costs of every unit, as well as their operating characteristics (e.g. start times or ramp rates). This seems simple; it is not. The costs of determining, updating and often litigating determinations of unit marginal costs are not small;

- ***Regulatory risks and the cost of capital:*** Unbridled intervention into market prices and outcomes can have a significant influence on the perceived risks of investors in new generation assets. This can, over time, lead to higher prices, as entry decisions are delayed until expected prices are even higher. Since electricity generation is so capital intensive, a modestly higher required return on equity or debt will lead over the long-term to substantially higher prices for customers. Any form of regulatory intervention must balance the short-term and long-term effects on prices.

- ***Effects on investment:*** If perceived regulatory risks grow too high, some forms of investment may be indefinitely delayed. One aspect of market power intervention in the United States has been its unpredictability – regulators have not been clear about when intervention is required, nor have the measures to be implemented been discussed in advance. The result might be that the limited set of possible equity and debt investors lose interest, and necessary investment is not made.

- ***Distorted peak price signals:*** Prices send signals about when consumers should use or not use electricity. If price signals are distorted through blanket price caps at very low levels, for example, then these price signals will be eliminated. This imposes costs on the entire economy.

5.1.3 A practical balance

It is outside the scope of this paper to propose what the detailed costs and benefits of various options for controlling economic withholding would be. On a more practical level, a qualitative assessment of the costs and benefits suggests that “extreme” policies on either side are unlikely to be efficient or workable:

- Attempts to achieve the effects of perfect competition through regulatory intervention (e.g. the California proxy price methodology) are excessively intrusive. The short-term gains from reducing some price spikes may be accompanied by high levels of regulatory risk, a higher cost of capital for generation investors, and an unwillingness to invest in new plants. If the market is so truly broken that regulation of all market prices in all hours is truly required, then perhaps it would be better to have no market at all. There are more effective regulatory alternatives than competition in this case, with lower risks, and probably lower prices over time.
- At the same time, the characteristics of electricity and electricity markets suggest that the inefficiencies and wealth transfers arising from market problems (including severe levels of economic withholding) may be so high as to be unacceptable. A *laissez faire* approach is unlikely to be sustainable. A complete absence of controls would impose significant price risks on consumers, and would be difficult to hedge effectively. From a policy perspective, there is a need to ensure that even "bad" market outcomes are not socially and politically untenable.

In summary, competitive forces should be allowed to work, to the extent possible. However, due to the very nature of electricity markets there is a need to balance consumer protection in the short term without interfering with the longer-term ability of market forces to sort out competitiveness problems.

5.2 DEFINING ACCEPTABLE OUTCOMES

While economists have clear definitions of the characteristics of an efficient market, there is much less consensus on the characteristics of acceptable outcomes with respect to electricity prices. The U.S. Federal Power Act, which governs the operations of power markets in the United States, states that rates – including market-based rates – should be "just and reasonable." The FPA, which is decades old, provides no working definition of just and reasonable, although subsequent court cases have interpreted market outcomes that have been significantly influenced by market power (including economic withholding) as unjust and unreasonable. Since no actual market is likely to be *completely* free of the influence of market power, use of an absence of market power standard (i.e., perfect competition model) is of little practical use. If market outcomes and prices are to be subject to review, then a more practical standard is necessary.

5.2.1 Setting standards

In defining a standard, a practical distinction should be made between standards that would seek to compare market prices to the outcomes of perfect competition, within some range (e.g. a maximum price-system marginal cost difference of 10%), and those that would more broadly define acceptable outcomes as being the results of a market where bid and competitive behaviors were acceptable. In the latter, for example, no bid in peak periods, where economic withholding would presumably be most effective, can diverge by more than $100/MWh from previously accepted bids. This distinction, while it appears small, is practically significant:

- In comparing market prices to those that might have been achieved under perfect competition, the regulator will have to re-create all bids in the market, based on assumptions for the determination of true short-run marginal costs (SRMC). This is very difficult in both theory and practice, as the Californian experience has demonstrated;

- The alternative approach would have the standard be not on short-run market outcomes, but rather would focus on individual bidding behaviors in the real-time market. The screen for acceptability under this approach would be to detect and prevent specific bidding strategies that would significantly affect prices through economic or other forms of withholding. In the absence of such strategies market outcomes would be deemed acceptable.

The latter approach has clear advantages, especially in a market that is generally competitive. It does not require regulators to engage in *ex post* price setting, based on hypothetical calculated market prices. It focuses attention on the key hours (e.g. peak periods) when competitive forces may be insufficient to constrain market outcomes, without requiring that all prices come under detailed scrutiny. Finally, by focusing on bidding patterns and deviations within a broader band, the scope for error and regulatory costs are reduced.

5.2.2 Experience in U.S. jurisdictions

The Appendix in Section 7 provides a more detailed analysis of experience in some other jurisdictions with respect to measurement and mitigation of economic withholding in electricity markets.

In summary, the U.S. ISOs have generally used a mixture of these approaches in an attempt to set "reasonable" prices. The New York and New England ISOs have adopted the bid screen approach described above, where bids are compared to reference bids determined on the basis of prior accepted bids or regulatory determinations of marginal cost. The New York and New England protocols use a broad trigger mechanism to determine if bids have changed significantly (e.g. by 300% or $100/MWh, whichever is lower), and to determine if such bid changes will have a material impact on clearing prices.

Recent FERC proceedings have moved California towards trying to reset prices for refund purposes based on a hypothetical determination of system marginal costs (based on replacing bid prices into the ISOs real-time markets with regulatory estimates of marginal costs, although without changing quantities offered). This is time-consuming, even though categories of valid SRMCs (e.g. the opportunity costs of hydro plants, and NO_x emissions costs) have been excluded. Going forward, cost-based mitigation has been established across the WSCC.

5.2.3 Ranking measures for dealing with economic withholding

In terms of the economic withholding mitigation measures described in the previous sections, there is a clear hierarchy from the economic perspective in terms of the measures that are most likely to create net benefits over time:

1. Changes to market rules that promote overall efficiency and competitiveness, such as lowering barriers to entry and eliminating rules that create incentives to withhold;

2. Structural approaches to improving market performance. For example, holding restrictions may be considered on a go-forward basis for managing concentration levels in the marketplace.
3. Market rules and policies that encourage price responsiveness of load (in forward and real-time markets) to be increased;
4. High "damage control" price caps, that could prevent significant wealth transfers from a small number of anomalous pricing periods;
5. Bid screens that seek to control market power in periods when the market is found to be generally uncompetitive, and when the price effects of withholding could be sustained and significant.

Price cap controls at low levels (e.g. as implemented in California) are highly distortionary, and are a poor second-best to the approaches listed above.

6 CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the conclusions of the paper, and provides recommendations for addressing economic withholding within the Alberta electricity market.

6.1 CONCLUSIONS

As outlined in Section 2, economic withholding is defined as an exercise of market power intended to raise prices in the market above competitive levels by pricing offer blocks high enough to effectively "withhold" capacity, or to reduce the quantity of supply that is offered at "competitive" prices. There continues to be a debate within industry around how "competitive" levels are defined; nonetheless, the practice of offering offer blocks at high, non-competitive prices is defined as economic withholding.

An assessment of the impact of economic withholding in Alberta and need to mitigate market power led to the following conclusions:

- Monopoly power due to supply is more significant than monopsony power from demand. Accordingly, the market needs to be balanced to ensure prices are competitively determined. (International research, Section 3)
- Market power is difficult to measure; agreements on thresholds for economic withholding are even more difficult to achieve. Additionally, the cost of monitoring and mitigation efforts may likely outweigh the benefits. (International research, Sections 4,5)
- The real-time market is relatively competitive and responsive to market changes except near to and during the delivery hour wherein the elasticity of both the demand and supply curve is low. While the Alberta market has relatively high levels of price responsive load, the impact is insufficient in comparison to the ability of supply to vary its availability. (Section 3)
- The impact of economic withholding that results from restatements during periods when the market is less able to respond (i.e., during the delivery hour) can have a significant and immediate impact to the marketplace. Resulting prices can be higher than would occur due to scarcity alone (i.e., evidence of exercise of market power). (Section 3)
- While restatements can occur at any time of the day, it is concluded that the market is able to respond to market changes outside of the delivery hour, and accordingly further monitoring and mitigation is not warranted at this time. (Section 3, 4 and 5)

6.2 RECOMMENDATIONS

As outlined throughout the paper, it would be extremely difficult and labour intensive to define and monitor limits within the market for economic withholding. Further, since the market is relatively competitive, the merit for such "limits" needs to be debated. However, in the case of the "delivery" hours, instead of a defined limit, it is proposed that limitations on restatements be imposed, which will mitigate the impact of economic withholding.

The greatest focus should be on implementation of measures that will strengthen market forces and competitiveness.

6.2.1 Specific recommendations with respect to economic withholding

The following recommendations focus on the specific performance of the Power Pool of Alberta's real-time market. These are designed to address potential specific competitiveness issues arising from economic withholding in a relatively limited number of hours.

- Preservation of the price cap as a "damage control" cap, in order to limit the distortions and transfers that might be created by an unforeseen market flaw or exercising of market power. The appropriateness of the price cap level at $1,000 should continue to be monitored and consideration given to raising the limit to facilitate other market objectives such as increasing demand side participation.
- Revision to the locking restatement rule to prevent very short-term market power from being exercised – it is recommended that the locking restatement cannot be used to change offer volumes for the hour in which the restatement is submitted and the following hour.

6.2.2 General recommendations

The following recommendations are focused on further developing market competitiveness:

- Further work on market information and access thereof to ensure that the market obtains the information it needs to be competitive, but that market power cannot be exercised through information access.
  - An examination of reinstatement of the merit order graph will be conducted within the context of the market information analysis.
  - Improvement in the price forecasting methodology for real-time forecasts to encourage market response. Since market response is key as an input to how much mitigation is required, further efforts are warranted in ensuring that the market receives sufficient and timely information, especially regarding price.
- Further development of market monitoring procedures, along with the development of appropriate measures to determine whether the Alberta energy market is operating competitively;
- Further development of market monitoring procedures to examine incidences of physical withholding, especially in concert with non-competitive offers.

7 APPENDIX – EXPERIENCE IN OTHER JURISDICTIONS

Assessment of market power has been one of the most vexing questions in the restructuring process, especially in the United States. The Federal Power Act, as interpreted in various Federal court decisions, requires that electricity prices be "just and reasonable", and that market power be adequately mitigated in order for sellers to sell power at market-based rates. While this provides a legal basis for market intervention, the FERC has found it very difficult to come up with workable standards in respect of market outcomes, and has acted on a case-by-case basis.

The framework for FERC's vision of future wholesale markets was established in Order No. 2000, released in late 1999. The Order requires transmission owners to join a Regional Transmission Organization (RTO), which would be responsible for transmission operations, access, planning and coordination. Order 2000 specified that all RTOs must carry out market monitoring functions, but was vague about the precise duties and policies that were to be implemented. The market monitoring approaches and policies of the existing ISOs provide clues about how future RTOs will likely function.

7.1 MARKET MONITORING AND MITIGATION FUNCTIONS

There is a set of market monitoring functions that are common to all of the existing U.S. ISOs: PJM, New York ISO, ISO New England and the California ISO. These include:

- **Data gathering:** All of the ISO market monitoring plans require that the market monitor gather data to allow assessments of market competitiveness to be made. Much of the data on load, supplies and state of the transmission system is gathered directly from ISO operations. Several of the ISOs have indirectly gathered existing marginal cost-type data (e.g. on plant heat rates) in attempts to make direct price-cost comparisons.
- **Assessment of market competitiveness:** Market monitors at the existing ISOs provide periodic assessments of the competitiveness of their markets to ISO boards and FERC. This takes many forms. The New York ISO market monitor has generally provided an overview assessment, which looks at the state of the market as a whole. The California ISO Department of Market Analysis has provided more detailed analysis of market behavior, including attempts at detailed assessments of bids as compared to estimated marginal costs.
- **Assessment and recommendations regarding rules changes:** The rules of the U.S. ISOs continue to evolve. To varying degrees the market monitors have been involved in proposing or assessing rules changes, both within ISO committees and before FERC. The market monitoring unit at PJM, for example, is empowered to file proposed rule changes at FERC, under board approval.
- **Assist regulatory agencies:** The market monitors are generally allowed or required to assist outside regulatory agencies (e.g. FERC or the U.S. Department of Justice Anti-Trust Division) on competitiveness investigations.

With regards to bid mitigation or corrective action, the experience is less coherent, as detailed in the individual sections below. In general, while FERC retains jurisdictional authority over prices, it has allowed ISOs some ability to change or "correct" prices in certain situations. Developments in this regard have generally followed the patterns of market prices, as one would expect. ISOs with more stable prices, such as PJM, have been less drawn into detailed ISO-determined bid mitigation, while many ISOs (e.g. New York, California and New England) have been more willing to seek direct bid mitigation.

7.1.1 Price caps

All of the existing U.S. ISOs have implemented some form of price cap on their energy market. PJM started with a $1000/MWh cap. Price caps – both “hard” and “soft” – were introduced at successively lower levels in California. ISO New England did not start with a price cap, but a $1000/MWh cap was introduced in 2000 in response to market problems. The New York ISO has the same cap level.

7.2 PJM

The PJM market covers several Mid-Atlantic States, and has become the benchmark for market design in the United States. The PJM model, which includes locational marginal pricing (LMP), and centralized optimization of energy and ancillary services bids in day-ahead and real-time markets, is the basis for the FERC’s Standard Market Design, which may be used in future Regional Transmission Organizations across the United States. PJM is currently participating in discussions that would see it form a key component of a proposed Northeast RTO (which would also include the existing areas covered by ISO-NE and the New York ISO). It is also developing a link with the Midwest ISO.

7.2.1 Market development

The structure of market monitoring in PJM, and regional policy regarding economic withholding, reflects the general consensus that has characterized wholesale market implementation in the region. This consensus is not accidental, but reflects both state-level policy and the continuing dominance of incumbent utilities:

- ***Strong vertical integration by heavily regulated utilities:*** Unlike other U.S. jurisdictions, many utilities in PJM were not required to divest generation assets, and remain vertically integrated. With the exception of certain regions of Pennsylvania, retail competition has also been slow to develop, and most customers are still served on state-regulated default tariffs. The result of the structure is that the PJM wholesale price is not of financial consequence to most customers, or even to the utilities. There has therefore been less pressure to intervene in market outcomes.[12] As many of the major generation utilities are largely hedged against their loads, these firms have had little incentive to exercise any latent market power. This may change somewhat in the coming twelve months due to regulatory developments in New Jersey, in particular.
- ***Favorable supply-demand balance:*** Unlike some other regions, PJM entered into wholesale restructuring with a general surplus of capacity. While there are significant transmission constraints within PJM, there has not been a significant shortfall of capacity in PJM as a whole, or even in its Eastern region. Load growth in PJM has been modest compared to many other areas of the United States.

[12] This structure has some strong parallels to Alberta, under the previous system of “legislated hedges”. Despite the fact that a wholesale market price existed, this was primarily a transfer price within a vertically integrated and cost-of-service regulated utility.

Despite problems in 1999, mainly linked to shortfalls in neighboring regions in the Midwest, prices in PJM have been generally stable and predictable. Market participants have also generally expressed the view that the market has been reasonably competitive, with the exception of concerns about the PJM installed capacity ("ICAP") markets that arose in the first half of 2001.[13] Price stability, in combination with the fact that very few consumers are affected by PJM market prices, have limited the number of calls for a more interventionist approach by PJM with respect to market power monitoring and mitigation.

7.2.2 PJM market monitoring functions

The structure and philosophy of market monitoring in PJM reflect the patterns of market development, and the more hands-off approach of the original filing utilities. The market monitoring unit in PJM is relatively small in numbers of staff, and limited in responsibilities. It basically acts in an advisory manner, advising on general market competitiveness and changes to market rules. Unlike similar organizations in other U.S. markets, PJM has limited ability to "correct" prices or to reset bids based on assessments of marginal cost, although the PJM Tariff does allow capping of bids used to set LMPs in constrained load pocket areas.

Treatment of economic withholding in energy markets has been less of an issue in PJM, due to the structural reasons listed above. The PJM market monitoring units maintains indices on market competitiveness, include price-cost (e.g. short-run marginal cost) markups, but it has also realistically recognized the limitations of this approach, due to the opportunity costs arising in neighboring markets, etc.

In summary, PJM has had in many ways the least interventionist approach of any U.S. ISO to date, likely reflecting the regulatory and transitional process in the region.

7.3 NEW YORK ISO

The New York ISO has adopted a more intervention-oriented approach to its energy and ancillary services markets. Like New England, state policy in New York supported widespread divestiture of generation assets, implying that changes in market prices have had substantial financial impacts on market participants. Peak prices, like those in ISO-NE, have therefore been a subject of near continuous dispute.

7.3.1 Background on the New York power market

The New York ISO ("NYISO") covers New York State, which extends from sparsely populated areas near Quebec to the New York City and Long Island region, the most densely populated in North America. NYISO has substantial intra-system transmission constraints, which limit power flows into southeastern New York and into the New York City metropolitan region, where demand is concentrated. For this reason, much of the market monitoring and mitigation efforts in the NYISO focus on the high-cost, heavily transmission constrained "in-City" and Long Island sub-markets. In recent years the potential for capacity shortfalls in this constrained zone has risen, leading to worries about California-style shortfalls in New York City.

[13] PJM Market Monitoring Unit, Report to the Pennsylvania Public Utility Commission on Capacity Market Questions, November 2001.

When NYISO opened in 1999 it was probably the most complex power market design ever implemented. The NYISO design included not only day-ahead and real-time LMP-based nodal pricing for energy, but also an installed capacity market (ICAP) and market-based pricing of various ancillary services. The first months of operations were troublesome, due to design and procedural flaws, software bugs and a perceived lack of competition in some markets, especially for ancillary services. The high prices that resulted in some hours focused attention on market power monitoring and mitigation efforts.

The in-City market, which covers New York City and some surrounding suburbs, is effectively treated differently than the rest of the NYISO for pricing purposes. When generation assets in this area where sold off, a set of local market mitigation measures were included in the sale process. These constrain in-City prices to 105% of prices at a specific bus outside of New York City. Capacity market prices were also capped in-City.

7.3.2 Development of market mitigation in the NYISO

The original filings that created the NYISO included a market monitoring plan for approval by FERC. In response to early problems in NYISO, the FERC approved a price cap of $1000/MWh. This was initially approved as a temporary measure, although it is still in place following repeated extensions.

The NYISO and its market monitoring unit have implemented active market price mitigation, in response to perceived economic withholding which has impacted market prices. In 1999, NYISO implemented a mitigation plan that allowed the MMU to mitigate bids into the NYISO's markets, if these bids met certain trigger criteria. Mitigation measures are to be triggered to remedy conduct that is "(1) significantly inconsistent with competitive conduct; and (2) would result in a material change to one or more prices…"[14] The NYISO specifically identifies economic withholding as an activity that may trigger mitigation, defining it as "submitting bids for an electric facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a market clearing price."[15] Physical withholding is also defined as an activity that may require mitigation.

[14] New York ISO, NYISO Market Monitoring Plan, FERC Electric Tariff, Attachment H, Revised Sheet 467.
[15] *Ibid.*, Tariff Sheet 468.

With respect to economic withholding, the NYISO tariff is much more specific than most about the types of bidding behaviors that will attract mitigation. First, a reference bid level is established for each component of a generating unit's bid.[16] This reference bid level is established as:

- The lower of the mean or median of a unit's accepted bid or bid components over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices;
- The mean of the locational marginal price at the unit's location during the lowest-priced 25% of the hours that the unit was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices; or
- A level negotiated with the market participant submitting the bid, provided that such a level was negotiated prior to the occurrence of the conduct being examined by the NYISO.

If there is insufficient accepted bid history to support these methods, or if negotiations are unsuccessful, then the NYISO will determine a reference bid level with respect to estimates of unit marginal costs.[17]

Once these reference bids have been established, the thresholds for identifying economic withholding that warrant mitigation can be determined. All thresholds are set in respect to the reference bid component for the individual unit. These are different for the various bid components:

- *Energy and minimum generation bids:* A 300% increase or an increase of $100/MWh, which ever is lower;
- *Real-time spinning reserve bids:* a 300% increase or an increase of $50/MW, whichever is lower;
- *Other reserve bids:* a 300% increase or increase of $100/MW, whichever is lower; and
- *Start-up bids:* A 200% increase.

In order to "avoid unnecessary intervention" in the markets, the bid mitigation measures will not be implemented unless there is deemed to have been a material impact on market prices of guarantee payments calculated by the NYISO.[18] The materiality thresholds are defined in the NYISO Tariff as being:

- An increase of 200% or $100/MWh, whichever is lower, in the hourly day-ahead or real-time energy LMP at any location, or of any other price in the NYISO markets; or

16 The NYISO does not use the single-part bidding format used in the Power Pool of Alberta, but like PJM and ISO NE relies on a multi-part bid format that includes bid start costs, no load costs and incremental energy blocks. A reference bid component must therefore be calculated for each of these elements.

17 *Ibid.*, Tariff Sheet 470-71.

18 Guarantee payments are payments made to generators under the NYISO's centralized scheduling protocol. A unit started by the NYISO is guaranteed to at least cover its variable costs for starting and running at a minimum level over a day, through what are called "bid production cost guarantee" payments.

- An increase of 200% in guarantee payments to a market participant in a day.[19]

7.3.3 Implementing automatic bid mitigation

Given the complexity of the above trigger mechanisms, implementation is a significant issue. Initially, market mitigation was implemented manually in the security-constrained unit commitment (SCUC) process that established the generation schedule and set day-ahead market prices. As the NYISO employs a multi-part bidding process, and simultaneously schedules and optimizes reserves, the SCUC software cannot rely on simple linear programming algorithms, or the "stacking" approach used by the Power Pool of Alberta. The SCUC process takes some hours to complete in New York, and may require significant operator input. Therefore, it was not possible to mitigate all bids before day-ahead prices were posted and became binding.

Prices spiked in the NYISO during a few days in the summer of 2000. The reasons, inevitably, have been disputed. Load-serving entities claimed that the increased prices were due to economic withholding, and that this spike had cost consumers many millions of dollars. NYISO claimed, in a FERC filing, that the market mitigation plan outlined above, and previously implemented, had failed, as NYISO had been unable to mitigate prices before bids were accepted in the day-ahead market. The NYISO sought to employ an "automated mitigation procedure" (AMP), which would implement the various threshold mechanisms above in software before prices were set. This, NYISO claimed, would remove the ability of generators to benefit from exercising market power for a single day, before mitigation could be imposed. The implementation of the automated mitigation procedures was approved by FERC on a temporary basis, although these have been extended.

7.3.4 Proposed penalties for economic withholding

The NYISO also filed in July 2001 for permission to implement a set of escalating penalties for "repeated violations of mitigation thresholds". Financial penalties would be imposed for submitting false information on unit outages and derates, or failure to follow dispatch instructions, which caused a material increase in market prices. Such financial penalties would also be imposed on generators that had been subject to mitigation measures for economic withholding.

FERC, in an Order issued August 31st, 2001, approved penalties for failure to follow dispatch instructions, but declined to allow NYISO to impose additional financial penalties for economic withholding.[20] FERC stated that NYISO had sufficient mechanisms to control economic withholding, and that NYISO had not made a sufficient showing otherwise.

7.4 ISO NEW ENGLAND

ISO New England (ISO-NE) covers the six New England states. In New England, almost all of the investor-owned utilities in New England underwent near-complete divestiture of their generation assets (with the exception of some nuclear assets that never set the price).

[19] *Ibid.*, Tariff Sheet 471.
[20] Federal Energy Regulatory Commission, *Order on Tariff Filing*, Docket ER01-2489-000, Aug. 31st, 2001.

7.4.1 Market development

Unlike PJM, ISO-NE immediately implemented not just an energy market, but separate clearing markets for ancillary services as well. Market problems started to develop immediately, around various aspects of the market rules and ISO-NE's complex software and systems. This included problems with scheduling of energy-limited units (e.g. hydro), exports, the Operable Capacity Market, which was eliminated under FERC Order, and numerous other rule changes. Disputes over pricing outcomes in New England continue into 2002.

Adding to this design complexity, ISO-NE has undergone near continuous rule changes. The original ISO-NE design was in some ways similar to the Power Pool of Alberta, with a single regional energy clearing price based on single-part energy bids, set *ex post*.[21] ISO-NE has since implemented multi-part bids (e.g. bid start costs, no load and energy blocks), and a binding day-ahead market. It is in the process of implementing a congestion management system (CMS) based on the LMP model used in PJM and New York.

After market opening in 1999, ISO-NE engaged in frequent corrections and changes to market prices. The initial ISO-NE market rules – for a short transitional period - allowed the ISO broad scope to correct errors and market outcomes that were inconsistent with a "workably competitive" market under Market Rule and Procedure 15. The "workably competitive" language was eliminated in a later tariff filing.

Given the software errors in ISO-NE, and the immediate perception that economic withholding was driving at least some prices, many hourly prices in the New England market were being reset on a day-to-day basis. FERC allowed an extension of these powers for another few months, and then limited price changes to more specific operational and software problems, in response to complaints by some market participants. FERC however did cap market prices at $1000/MWh in 2000, and has maintained this cap ever since.

7.4.2 Bid mitigation in New England under the initial ISO Tariff

The original ISO-NE tariff was based on an assessment made by filing utilities that the market would be competitive. Perceptions changed after their assets were largely divested; the same utilities (which are generally load-serving entities) complained that the market was not competitive. Mitigation procedures in the original ISO-NE tariff focused on market power of constrained-on units, many of which are located in the Boston metropolitan area. Two screens were implemented under ISO Market Rule 17:[22]

- ***Structural screen:*** If a transmission constrained region was identified, a structural screen was first applied. This screen checked to see if a resource was pivotal, e.g. could the ISO run the system without it. If the answer was no, then the resource failed the structural screen and mitigation was required. If there were at least three

[21] ISO-NE differed of course in having bid-based ancillary services markets, and markets for installed capacity.

[22] ISO New England, Rule 17: Market Monitoring, Reporting and Market Power Mitigation, Revised April 13th, 1999.

competing bidders to provide the needed resources (five under certain circumstances), then the structural screen could be passed and mitigation avoided;

- ***Price screens:*** If the structural screen was not passed, economic withholding was judged to be possible and a price screen was to be applied. This price screen could take two forms. For units that ran regularly in merit, the price screen calculated a "screening percentage" –a markup over a pre-determined Reference Price – based on the number of hours run out of merit. For example, a unit that generally runs in merit (i.e. not constrained-on), but that runs for a few hours out-of-merit would be allowed to bid up to 150% of its reference price in those constrained-on hours. For units that seldom run in merit, the percentages were higher, but with bids compared to the current hour energy clearing price (or a set of comparable clearing prices).

7.4.3 Recent New England mitigation developments

ISO-NE was criticized in a series of FERC Orders in 1999 and 2000 for allowing excessive discretion in implementing mitigation of bids. Since then, ISO-NE has moved towards the NYISO approach of pre-determined thresholds and more automatic mitigation of bids. This is consistent with ISO-NE's plans to link up more closely with NYISO, in a combination or in a future Northeast RTO.

Recent ISO-NE policies with respect to economic withholding focus not only on units in transmission constrained regions, but like the NYISO mechanisms looks at all market prices. The mitigation process includes:[23]

- ***Calculation of reference bids for all unit blocks:*** ISO-NE calculates a reference bid for each component (e.g. energy blocks, start costs, no load costs), based on accepted previous bids, under a complex weighting formula;

- ***Investigation thresholds:*** Like NYISO, the ISO-NE process triggers mitigation only when impacts are deemed to be significant. This includes an increase of 300% or $100/MWh over the Reference Price for energy bids, and 200% increases in no load and start cost bids.

- ***Impact thresholds:*** Finally, to be considered for mitigation the bids must have the potential to have a material impact on clearing prices. This is defined as $100/MWh or an increase of 200% for the energy clearing price. Where mitigation is triggered, the supplier's bid is replaced with a default bid set to the pre-determined Reference Price.

7.5 CALIFORNIA ISO

The tariff filings that separately created the California ISO (Cal ISO) and California Power Exchange (CalPX) created separate market monitoring units as well, backed by an "expert committee" to advise on market development issues. The Cal ISO market monitoring unit -currently called the Department of Market Analysis (DMA) – has

[23] NEPOOL Market Rules and Procedures, Section 17, Tariff Sheet 1750 ff.

become a significant player in the debate, and is currently acting as the analytical team on behalf of the ISO in the litigation regarding past California market prices.

7.5.1 Assessing market competitiveness in California

California was a strong advocate of Lerner Index (direct price-system marginal cost) approaches to assessing market power in electricity markets, based partially on a set of papers submitted in the market surveillance committee. The Cal ISO, however, is a particularly difficult market in which to apply these approaches conclusively, for a number of reasons:

- The California power market is well-integrated into the larger Western power market, as California has long been an importer of power from the Pacific Northwest in particular. Prices in California have tended to follow WSCC trends and *vice versa*. Import pricing, which would have partially determined Cal PX and Cal ISO prices in many hours, would have been influenced by non-thermal production decisions as far away as British Columbia;
- California (and the WSCC in general) has a significant number of energy-limited units, such as hydro, pumped storage and thermal units constrained by emissions controls. Determining the true marginal costs of such units, which are in reality opportunity costs, is difficult; and
- The complex market design used in California tends to make comparisons of bids and marginal costs difficult, due to the presence of opportunity costs arising in sequential PX, ancillary services and Cal ISO markets.

Despite these theoretical problems, and the controversy that has surrounded the price-marginal cost assessments made by DMA, the regulatory concepts has been established in California (and at FERC) that the appropriate benchmark for assessing market outcomes is a “perfectly competitive” price, estimated from the marginal fuel and O&M costs of the highest cost unit running in an interval. Litigation continues about what “competitive” prices should have been, and how these should be calculated, absent the market flaws identified by FERC in its December 200 Order, for the purpose of determining refund amounts.

7.5.2 Mitigation actions in California

As prices started to rise in California in 1999, market re-design efforts began, often focusing on the ancillary services markets. Concerns over market power started to rise, especially as the major incumbent utilities (PG&E, Southern California Edison) noted that while the retail price was fixed by agreement, their costs of procuring power in the Cal ISO and Cal PX was rising rapidly. The disconnect in wholesale and retail prices eventually led to the bankruptcy of PG&E, and severe financial stress at Southern California Edison.

Wholesale price caps have been imposed in California since 1999. These price caps were lowered time and again as its markets were viewed as increasingly dysfunctional. The FERC moved away from pure price caps in 2001 mitigation Orders, relying instead on a “proxy price” method for establishing mitigated market prices, combined with a “must offer" obligation on suppliers. A timeline of the most significant mitigation actions in California is shown in Figure 15.

Figure 15: Timeline of California Mitigation Actions

May, 1999	**FERC allows Cal ISO to impose a "purchase price cap" at $750/MWh, later extended to Nov. 2000**
June/Aug 2000	**Price caps lowered to $500/MWh then $250/MWh**
Aug. 23, 2000	**FERC institutes investigation into California prices**
Dec. 15, 2000	**FERC finds market, flawed, orders $150/MWh "breakpoint" cap Cal ISO markets, with sales above this price not setting price**
Apr. 26, 2001	**FERC adopts proxy mitigation plan, with clear price set on estimated MC of most expensive thermal unit running**
June 19, 2001	**FERC establishes mitigation throughout the WSCC, based on proxy price of gas unit in California**
July 25, 2001	**Refund hearing started for Oct. 2000-June 2001 Cal ISO prices**
Sept., 2001	**FERC holds hearing on Pacific Northwest prices; FERC judge later determines market was competitive**
Dec., 2001	**Initial date for Cal. refund hearing, postponed until March 2002**

The proxy price methodologies, in simplified terms, establish the maximum clearing price as the marginal cost of the highest cost gas-fired unit operating in an hour (or ten-minute ISO interval). In effect, imports, hydro units and other units are not allowed to set prices, and opportunity costs and scarcity values are ignored. The use of the proxy price methodology assumes that competitive forces are ineffective, and instead relies on regulated (marginal) cost to set wholesale market prices.

7.6 ENGLAND AND WALES

Market power issues have dominated the debate about the England and Wales Pool from the beginning, and continue under the New Electricity Trading Arrangements (NETA) that replaced it. A specific policy objective of NETA was developing a bilateral-based market that was considered less easily gamed than the single clearing price E&W Pool.

The roots of the market power problem in the Pool were structural. At the time of privatization, the UK government created only two large thermal generators (National Power and PowerGen), and a third nuclear generator (Nuclear Electric, now British Energy). It was very quickly recognized that the two major thermal generators possessed substantial market power.

In evaluating market outcomes, the UK electricity regulator OFFER (now OFGEM) generally steered away from direct bid-marginal cost comparisons, and relied more on assessments over time versus average costs (e.g. including O&M and return on capital) and entry costs. The regulator also imposed a cap on average prices. In terms of policy, regulatory attention focused on new entry, divestiture of some thermal plant to new participants (including Eastern Group in the mid-1990s, and AES and Edison Mission later in the decade). Due to falling fuel prices, substantial new entry by gas-fired combined cycle plants, divestiture and changes to market rules, prices fell substantially over the latter years of the decade.

7.6.1 The proposed Market Abuse License Condition

Despite these falling prices, and a generally adequate supply, OFGEM sought in May 2000 to introduce a new Market Abuse License Condition into generator's licenses, to allow it to explicitly tackle economic withholding by generators.[24] Two generators, AES and British Energy, appealed OFGEM's actions with the Competition Commission.

OFGEM defended the need for the license condition due to the special nature of electricity as a product, which would allow a non-dominant firm with a relatively small market share to exercise market power.[25] Generally speaking, the market abuse license condition would provide additional powers to the U.K. regulator along the lines of those enjoyed by FERC – e.g. the ability to take measures against a non-dominant produce able to exercise market power through economic withholding, even if such behavior was unilateral and would not be contrary to normal competition law.

7.6.2 Review by the Competition Commission

The Competition Commission rejected OFGEM's appeal for a special license condition, suggesting that OFGEM had not made it clear when anticompetitive behavior had occurred. Comparisons with short-run marginal costs were rejected, as not allowing peaking units to recover their costs. OFGEM had suggested that it would make cross-sectional comparisons of pricing (similar to those encapsulated in the reference bids in the NYISO and ISO-NE mitigation plans) as a means of determining when conduct was anticompetitive. This too was rejected by the Competition Commission, which suggested that it was "normal commercial behavior for a profit-making company to increase its bid price when there is a discontinuity in the supply curve…"[26]

Ultimately, the Competition Commission rejected not just the proposed Market Abuse License Condition, but also the idea that regulatory attempts to reproduce the conditions of perfect competition were productive, especially where the regulator had produced such a limited framework for judging when behavior was competitive and when it was not. In its decision, the Commission stated clearly that the costs of such intervention, which would include uncertainty and decreased investment, were likely to exceed the potential benefits of eliminating any residual market power.

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[24] Office of Gas and Electricity Markets, *Introduction of a Market Abuse License Condition into the Licenses of Certain Generators: OFGEM's Initial Submission to the Competition Commission*, May 2000.

[25] Simon Bishop and Ciara McSorley, "Regulating Electricity markets: Experience from the United Kingdom", *The Electricity Journal*, December 2001.

[26] *Ibid.*, p. 85.

7.7 ONTARIO

Market monitoring plans in Ontario are still under development. While the Independent Market Operator (IMO) has created a market monitoring program, and has begun the task of defining data collection, it is yet unclear exactly how market outcomes with respect to economic withholding will be assessed.[27]

7.7.1 Market concentration and the MPMA

In designing its restructuring regulation, the Province declined to break up the generation assets of Ontario Hydro, bundling them into a single firm (Ontario Power Generation) that will initially control over 70% of generation initially, although "decontrol" provisions should lower this level over time. The scope for imports from neighboring markets is insufficient to remove the potential for significant market power to be exercised.

In place of a structural solution to market power issues, Ontario developed a Market Power Mitigation Agreement (MPMA), negotiated between the government (including the Ministries of Energy and Finance) and Ontario Hydro. This set of agreements not only does not take steps to lessen the scope for market power, it specially allows Ontario Power Generation to exercise market power to achieve "pricing outcomes that are consistent with the terms of the agreement."[28]

The MPMA consists of a revenue cap on Ontario Power Generation (OPG), which refunds revenues in excess of a fixed amount (initially determined to be $38/MWh) for the first four years after the market opens. The refund above the pre-determined Average Price (e.g. $38/MWh) is calculated based on a Contract Required Quantity (CRQ), which may not cover the full output of OPG. If OPG is long against the CRQ in a period, for example, it may have strong incentives to raise prices using economic withholding strategies.

27 Independent Electricity Market Operator, *Market Surveillance Data Catalogue*

28 Ontario Energy Board, "A Revised Basis for Estimating the Standard Supply Service Reference Price Upon Opening of the Retail Electricity Market in Ontario, Canada", prepared by Charles River Associates, July 24th, 2001.