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An Analysis of Market Power in the Alberta Electricity Market

by

Richard Paul Kendall-Smith

A THESIS

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Abstract

The thesis analyzes the ability of suppliers to influence the price of electricity in Alberta. To do this, the thesis develops two structural measures of market power using data on hourly offer curves and market clearing quantities from the Alberta wholesale electricity market over the period September 1st 2009 to June 30th 2012. These market power measures quantify the ability that the larger generating companies in Alberta had to influence the market price in each hour, and are used by the thesis to characterize the nature of competition within the Alberta wholesale electricity market. The structural measures of market power are also used in a regression analysis to show how the larger generating companies in the market changed their offer behaviour as their ability to exercise market power varied.

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Introduction

The objective of the thesis is to analyze the extent to which the larger generators in Alberta are able to exercise market power in the wholesale market for electricity. Market power is defined as the ability of a supplier to influence market clearing prices. Generator market power in wholesale markets for electricity has been, and will continue to be, an important topic for those who design and monitor the functioning of deregulated electricity markets. Market power is a subject of particular importance in deregulated electricity markets because these markets are especially susceptible to being influenced by the strategic behaviour of larger generating companies. Electricity, and the network on which it is transmitted, possess unique characteristics that differentiate electricity from most other products, and which enhance the ability of generators to exercise market power.

From an economic perspective, the exercise of market power is important because it can distort market outcomes away from the efficient outcomes of a competitive market. For example, the exercise of market power can mean that electricity for which a buyer's willingness to pay exceeds the variable costs of production is not produced. This results in a 'deadweight loss' to society. In addition, the exercise of market power can cause high cost generators to be supplying the market when cheaper alternatives are available, particularly when the cheaper generation is being withheld from the market to increase price.

The exercise of supplier market power in wholesale electricity markets also has the potential to cause significant transfers of wealth from consumers to producers in a relatively short space of time. In hours when the exercise of market power increases the price of electricity, consumers

buying from the wholesale market will pay more than they would have done under a competitive marketplace.

It is important to clarify at the outset that the exercise of market power in Alberta's electricity market is a lawful and rational exploitation of the ability and incentives available to the generators. The market design, structure, and rules of engagement in Alberta's electricity market are such that the larger generators are able to exercise market power under certain conditions.

The distinguishing feature of the Alberta market compared to most other deregulated electricity markets is that it is 'energy only'. The term energy only refers to the fact that generators in the Alberta market will only receive payments for the electricity that they supply onto the grid. Under this market framework generators must recover all of the costs associated with supplying electricity through their energy revenues. Therefore, under Alberta's market framework, generators require some degree of market power to recover the fixed costs associated with supplying electricity.

The fundamental premise behind the Alberta market design is that competitive forces will effectively regulate the market power of generating companies. In this way, the design of Alberta's electricity market is like many other deregulated markets and implicitly relies on the generation sector being sufficiently competitive. That is, the Alberta market design requires that prices are high enough to incentivise efficient generation investments if they are required. However, at the same time, the sustainability of the market requires that market outcomes are not exclusively determined by the actions of a few large generating firms. Consequently, the design of Alberta's electricity market means that measuring and monitoring the extent of generator market power is a subject of great importance to the industry.

The thesis uses data on hourly offer curves and market clearing quantities from the Alberta wholesale electricity market over the period September 1st 2009 to June 30th 2012 to develop two structural measures of market power. These market power measures quantify the ability that the larger generating companies in Alberta had to influence the market price in each hour. These market power measures are then used to characterize the nature of competition within the market.

The two structural measures of market power both use realized market supply and demand fundamentals to estimate the market power that each of the larger generators had in a particular hour. The first metric analyzes the offers submitted by competiting generators around the market clearing price to estimate the extent to which these offers limited the firm's ability to influence price. The second approach estimates how pivotal a generator's priced[1] offers were to the clearing of the market. The intuition here is straightforward, the more a firm's priced generation was needed by the market, the more influence these offers were deemed to have had on the market price.

The resulting quantitative evidence strongly suggests that each of the larger generators in Alberta had the ability to exercise significant levels of market power during a small percentage of hours within the sample period. The ability of suppliers to exercise market power during these hours was often driven by a combination of high market demand and a number of baseload coal-fired units being offline. The pool prices observed during these hours were frequently very high and, whilst these periods represented a small subset of the total number of hours, their impact on the prevailing average market price was notable. The average price during the sample period was

[1] 'Priced' here means offered into the market above $0.

$60/MWh but if the top 5% of hours are excluded, the average price in the remaining hours was only $33/MWh. In summary, the thesis shows that average prices for electricity in Alberta are driven by relatively few hours, and in these hours the market fundamentals illustrate that the larger generators in the province had a meaningful ability to influence the market clearing price. Therefore, the thesis illustrates a strong degree of correlation between market prices and the prevailing level of market power possessed by the larger generators.

That said, the two market power measures also indicate that in a large percentage of hours the ability of the larger generators in Alberta to influence market outcomes was actually quite limited. In many hours, Alberta's demand for electricity was too low or the level of competing generation was too high for the larger firms to materially influence price unilaterally. This distribution of competition is also evident in the distribution of electricity prices across the sample period. In most hours the price of electricity in Alberta is quite low, and almost 90% of the hours within the sample period fell below the average pool price of $60/MWh. In addition, for the vast majority of hours, the hourly price for electricity is highly correlated with the prevailing price of natural gas in the province. The conclusion here is that in most hours the Alberta electricity market is competitive.

The thesis also examines whether the two largest generating companies in Alberta (ENMAX and TransCanada) exercised their market power by offering their generation output into the wholesale market at prices above what they would have offered under competitive conditions. In particular, the thesis uses an econometric analysis to quantify how the offer behaviour of the two largest suppliers in the Alberta electricity market changed as their ability to exercise market power varied over the sample period. The thesis uses regression analysis to show that, after

controlling for input fossil fuel prices and other factors that influence the costs of producing electricity, some of the generating units belonging to these larger firms submitted a higher offer price when the firm had a greater ability to exercise market power, whilst other units did not. In summary, it is shown that the offer strategies employed on TransCanada's coal-fired generating units were very responsive to changes in the firm's ability to exercise market power. As the firm's ability to exercise market power increased, TransCanada offered its capacity into the market at higher prices. In contrast, the offer prices on ENMAX's coal-fired units were almost entirely unresponsive to changes in its ability to influence price. In terms of ENMAX's gas-fired units, the regression results show that these units were sometimes offered at a higher price when ENMAX had a higher ability to exercise market power.

This econometrics approach is also used to analyze the impact that the Offer Behaviour Enforcement Guidelines (OBEGs) had on the conduct of suppliers in the Alberta wholesale electricity market. Towards the end of 2010, Alberta's Market Surveillance Administrator (MSA) clarified to stakeholders that a unilateral exercise of market power was not deemed to be anti-competitive conduct. Prior to the MSA's consultation process, the rules surrounding unilateral exercises of market power were not completely clear, for instance previous Independent System Operator (ISO) rules specified that "*When a market participant in a dominant position exploits its market power in a way that adversely impacts upon the efficient, fair and openly competitive operation of the market, it will be considered an abuse of dominance.*"

By separating the sample period into pre- and post-OBEGs eras, the econometric models were re-estimated and a test of significance was used to see whether or not any changes in conduct had

occurred. Almost all of the units analyzed showed a significant change in the extent to which their offer prices varied with the level of market power held by the controlling firm. The regression results show that units controlled by TransCanada, TransAlta and Capital Power all increased their responsiveness to changes in their ability to exercise market power after the OBEGs. This observed change was most notable in the few hours when these generators had a significant level of market power. The implication is that prior to the OBEGs these firms were being somewhat 'reserved' in their offer strategies during these hours. In contrast, the offer prices submitted on ENMAX's gas units actually became less responsive to the firm's ability to exercise market power after the OBEGs. One potential explanation for this is that consumers may have purchased more fixed-price power through ENMAX's retail arm in response to the offer behaviour observed after the OBEGs. The increase in the level of fixed-price sales would in turn reduce ENMAX's incentives to exercise market power.

These empirical results lead to the following conclusions about the behaviour of the larger suppliers in the Alberta electricity market. Firstly, some of these generators are successful at increasing market clearing prices by raising their offer prices into the wholesale market when they have a greater ability to exercise market power. Secondly, the results indicate that the level of forward contracting has a significant effect on the conduct of the larger firms in the Alberta wholesale market. ENMAX, one of the largest generators in the province, also has a significant presence in the retail market and sells a large amount of its generation at fixed prices. As a result, ENMAX's offer prices are generally less responsive to changes in its ability to exercise market power when compared with the responsiveness of 'merchant' generating companies in the market. Finally, the econometric results imply that the OBEGs did have a meaningful influence on the conduct of the larger generators in Alberta. The major change here is that these

suppliers are now less reserved with the offer strategies that are employed when their ability to exercise market power is notably high.

To obtain a broad sense of the price implications resulting from the exercise of unilateral market power in the Alberta wholesale electricity market, the thesis undertakes a simple counterfactual analysis for the year 2011. In the counterfactual analysis TransCanada's Sundance B and Sheerness assets are offered into the market as if the firm had little to no market power. To do this, hours when TransCanada's ability to exercise market power was shown to be limited were used to estimate a 'competitive' offer price for these units. The counterfactual analysis takes any unusually high offer prices on the Sundance B and Sheerness units and reduces them to this competitive level. Everything else in the market is left unchanged and a counterfactual price is calculated. The results of this simple counterfactual analysis show that with these coal units TransCanada's influence on the market clearing prices was high. The average price observed in 2011 was $76. However putting the Sundance B and Sheerness units at competitive offer prices yields an average annual price of $52. The results of the counterfactual analysis are consistent with the intuition derived above. In the vast majority of hours, the counterfactual prices calculated were very close to the prices that were observed in the market, implying TransCanada did not offer strategically with the units, or its price impact of doing so was minimal. However, in the few hours that TransCanada's pricing strategies did have a price impact, it was sometimes very significant.

The remainder of the thesis proceeds as follows. In Chapter 1 the thesis will provide a broad explanation of electricity markets and market power, and why the unique properties of electricity mean that the exercise supplier market power is of particular concern in these markets. Chapter

1 will also outline the general motivations behind the deregulation of electricity markets. Additionally, Chapter 1 will discuss the economic implications of market power being exercised. Chapter 2 provides a history of the deregulation process undertaken in Alberta, explaining why the market was deregulated and how this process has been undertaken. Chapter 3 details how the Alberta wholesale electricity market operates and explains why the 'energy only' market design is an important consideration. Chapter 3 also discusses the supply and demand fundamentals in Alberta, explaining why and how these dynamic market fundamentals change to influence the extent of competition in the wholesale market. Chapter 4 then provides a review of the literature surrounding the subject of measuring market power in electricity markets. This review explains the variety of measures that have been used to analyze supplier market power in electricity markets, and outlines some of the benefits and drawbacks associated with each method. Chapter 5 details the two measures of market power that are used in the thesis. In particular, Chapter 5 outlines the economic rationale underpinning each of the two measures, and also explains how the measures are calculated using publicly available data from the Alberta Electric System Operator (AESO). Chapter 6 reports the results of the thesis, explaining how the market power of firms varied over the sample period and analyzing the distribution of generator market power within the sample. Chapter 6 also highlights the correlation between supplier market power and market prices. Chapter 6 then explains and reports the results of econometric approaches, which are used to highlight the relationship between generator offer behaviour and market power. Finally, Chapter 6 undertakes a simple counterfactual analysis to illustrate the observed impact of a single generator's market power on the price for electrcity in 2011.

Chapter 1: Electricity, Market Power and Economic Efficiency

1.1 Electricity Basics

The supply of electricity can usefully be broken down into four sectors: generation, transmission, distribution and retailing. The generation (or wholesale) sector refers to the production of electrical power using various forms of energy. Power stations create electricity by using mechanical energy to turn a turbine, which spins large amounts of copper wire between huge magnets at very high speeds. When a magnetic field is in motion relative to a copper wire it triggers the flow of electrons in the wire, thus creating electricity. Steam turbine generators, gas turbine generators, diesel engine generators and nuclear power all follow this principle, each providing a unique way to spin the copper wiring.[2] Therefore, electricity can be generated in a variety of ways. A common example is the use of pressurized steam to turn the turbines, since the required steam can be produced by burning fossil fuels (predominantly coal and natural gas), via nuclear fission, or by using renewable technologies such as biomass or thermal energy. Electricity can also be generated by turning turbines directly through burning natural gas, using falling water, or with wind energy.

The transmission of electrical energy refers to the transfer of electricity from generation sites to electrical substations located near local distribution centers. Voltage is the amount of electrical pressure that pushes the electrical current across the network, and this pressure is measured in

[2] The Electricity Forum website – How Electricity is Generated. The major exception to this principal is the use of solar panels, which generate electricity by converting solar radiation into direct current electricity using semiconductors.

volts (Stoft (2002)). The transmission of electricity involves the use of over-head power lines[3], transformers and substations to transmit power at high-voltages (generally 110 Kilovolts (kV) and above). High-voltages are used to reduce the energy losses[4] associated with transmitting electricity over long-distances.

From the transmission network, the power flows into the distribution networks which are used to deliver electricity to consumers. The transmission network and distribution network are linked by substations where the voltage is lowered to a level that can be used in homes and businesses. The distribution network carries electricity at low-voltages from the nearby substations to the end consumer.[5] Typically, distribution networks would include power lines of less than 50 kV, substations, pole-mounted transformers, and additional lower-voltage wiring. The target residential voltage in Canada and the United States is 120 volts.

The retail sector of the electricity industry is responsible for metering and billing consumers for their electricity use. A primary function of the retailing sector is to manage the risks associated with buying power from the wholesale sector by selling electricity to consumers at fixed prices. Electricity retailers can purchase power from the real-time 'spot' market or through long-term financial contracts and derivatives. Some vertically-integrated companies operate in both the retail and the generation sectors and generate a substantial portion of their retail sales themselves. Consumers in deregulated electricity markets can choose from a variety of

[3] Power can also be transmitted using underground power lines in urban or sensitive areas, although underground lines are significantly higher cost and also have greater operational limitations.

[4] Losses refer to the electrical energy that is consumed by the network.

[5] AltaLink website – Electricity at a Glance.

electricity price products – from 5-year fixed rates all the way to wholesale or 'flow through' pricing.[6]

While the basic structure of the electrical sector (wholesale, transportation and marketing) is comparable with other commodity markets, electricity has physical characteristics which mean that electricity markets are unique in important ways.

Maintaining Frequency: Supply = Demand

Electrical energy is a homogenous good that is injected into the transmission grid by all generators and is withdrawn by all end users. There is usually no way to identify the electricity generated by producer A with the power utilized by consumer B. A useful analogy is to think of the transmission grid as a large pond, with producers putting water into the pond while consumers are simultaneously taking water out (Griffin and Puller (2005)).

In addition, the characteristics of the delivered electricity must be uniform and carefully maintained. Power systems attempt to maintain a constant frequency, the rate at which alternate current alternates (Stoft (2002)). In North America power systems are operated at a frequency of 60 Hz. To deliver power at a certain frequency requires the generator to be synched with the grid and rotating their turbines at a certain rate. To maintain the overall frequency of the grid requires that the supply of power matches the consumption of power at every point in time. To continue with the above analogy, it is as if the amount of water being added and removed from the pond must always be the same, so that the level of the pond remains constant. If the consumption of electricity exceeds the amount being generated at any point in time, the electrical

[6] The Utilities Consumers Advocate website lists the range of retail contracts that are available in Alberta.

frequency on the grid will fall. If the frequency drops too much, generators and loads can automitically trip offline to prevent damaging their equiptment, and at this point the system controller loses all control over the grid. To prevent this, the system controller will shed load in the event of a supply shortfall, with the result being that a large number of consumers may be 'blacked-out'. On the other hand, if the supply of electricity exceeds the level of consumption at any point in time, the electrical frequency will increase, which has the potential to be severely dangerous and to substantially damage equipment connected to the grid. Therefore, unlike many other goods, electricity cannot be readily disposed of when the market is over-supplied, and if the grid is slightly under-supplied large areas of the market can lose the ability to consume power.

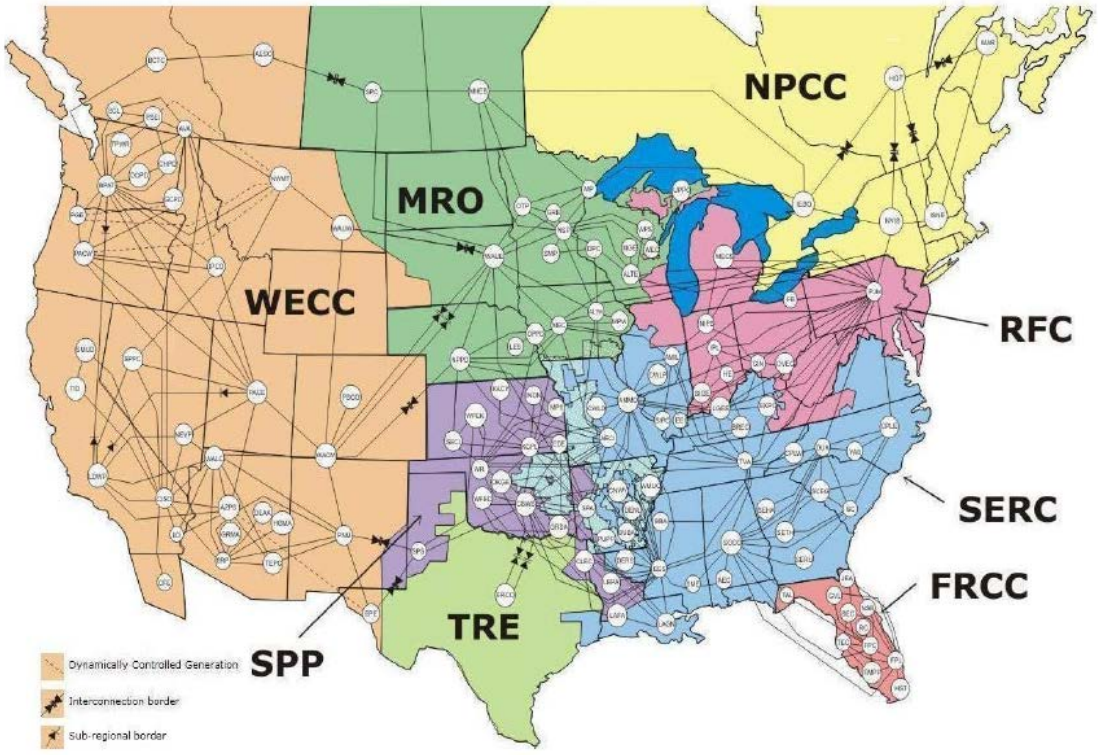
Because supply and demand imbalances have the potential to disrupt the entire electrical network, a System Operator is needed to coordinate schedules of generation, consumption and power flow and balance deviations from expected supply and demand. In effect, Adam Smith's invisible hand is hardly invisible for electricity markets (Griffin and Puller (2005)). The precarious need to balance supply and consumption on electrical networks also means that there is a vast amount of readily-accessible data in these markets. For example, the market supply curve for electricity in Alberta for a given hour is readily available on the AESO website. This supply curve shows the prices at which each generator in the province was willing to sell its electricity in that hour. This is in stark contrast to many other markets, where it is often difficult to get an accurate idea of market-clearing prices and quantities.

Maintaining the reliability of electrical networks is a non-trivial task since electricity demand is relatively volatile, changing significantly from one hour to the next as consumers go about their

daily routines, as weather conditions vary, or as large industrial loads alter their power demands. As a result, the aggregate demand for power will routinely vary by 50% over a single day in some jurisdictions (Griffin and Puller (2005)). In addition, the demand for power is not responsive to changes in price and electricity is prohibitively expensive to store. The overriding economic implication of these factors is that electricity markets are distinguished by time, so electricity produced at 5am may have a significantly different value to electricity produced three hours later.

These factors also mean that the need to continuously balance supply and demand requires a complex monitoring and control mechanism. An important aspect of this control mechanism is for the market to provide a range of services to ensure adequate reserve capacity so that the lights stay on in the event of unanticipated shocks to the market. A major way for electricity markets to manage disparities between supply and demand is through interconnections with other jurisdictions. For example, when a large coal unit trips offline unexpectedly in Alberta, the flow of electricity from British Columbia into Alberta will naturally increase. The electricity network in BC is itself connected to the Pacific Northwest and, in turn, to markets in California - these markets are all part of the Western Electricity Coordinating Council (WECC) area (see figure 1). Through the interties, jurisdictions can share the burden (and costs) of reliability. However, there are various 'good neighbour' policies and each jurisdiction is expected to alleviate its own reliability issues reasonably promptly.

Figure 1: Map of North American Electricity Jurisdictions (2008)



Therefore, each jurisdiction must procure enough reserve capacity to maintain system balance in the event of a large unexpected outage, or a surprising change in market demand. To do this, the system operator must also run a market through which generating and load facilities are paid to provide a variety of network support services. In Alberta these support services are procured by the Alberta Electric System Operator ('AESO') through the Ancillary Services ('AS') market.[7]

Kirschoffs Laws: The relationship between Generation and Transmission

The operation of electricity markets is further complicated by the fact that the location of generators and consumers is important. A local distribution company will withdraw electricity from the transmission grid at specific locations, and generators will inject electricity at specific

[7] The AESO's Ancillary Services participants manual provides a great amount of detail on the reserve products and services that are procured in Alberta.

locations. The 'transportation system' for electricity is more complex that in other commodity markets, such as oil or natural gas, because electricity cannot simply be sent from a generator at point A, along transmission line X, to be delivered at point B. Instead, electricity will flow along a transmission line in accordance with Kirchoff's laws, which dictate that power will flow along the transmission network according to the path of least resistance. Therefore, an injection or withdrawal of electricity at any one point on the transmission system will impact the system at every other point (Stoft (2002)). These network externalities have important consequences for the efficient operation of the market and the optimal investments in generation and transmission.

Short-run Implications: Congestion and Line Losses

The efficient operation of the electrical system at any point in time requires using the lowest cost generation to meet the market's demand. However, the use of a particular generator may be constrained, or the costs of using that generator may be materially influenced, by the prevailing conditions on the transmission network.

Transmission lines have a finite capacity and only a certain amount of power can flow along a particular transmission path. When this capacity is reached it prevents generation flowing from one area to meet the prevailing level of consumption in another, and the market is said to be congested. In this event, generation within the congested area cannot be used to service the load outside of the congested area, and generation outside of the congested area is required. Congestion on the grid will influence both the value of electricity, since power outside the congested area will be of more value, and the level of competition, because the ability of generation capacity in the congested to compete is limited.

In addition to congestion, the location of generation and loads on the transmission grid will also play an important role in determining the amount of electricity energy that is lost its transmission. The extent of these 'line losses' will depend on a number of factors but will fall as more transmission capacity is available and as the distance travelled is reduced. Therefore, the location of generators on the transmission grid can play an important role in determining their overall costs, as greater line losses will increase the costs of the power.

Long-run Implications: Investment Decisions

Given the preceding discussion, it is clear that there is an important relationship between investments in transmission and investments in generation. As outlined above, the ability of generators to get their product to market is influenced by their location and the strength of the transmission network. Therefore, investments in generation will be influenced by the interconnections provided by (or planned to be provided by) the transmission system. Conversely, the location and the amount of generation that is built will affect where and how much transmission capacity is required. Although it is clear that in the short-run the relationship between transmission and generation is complimentary[8], the long-run relationship may be viewed as one of substitutes; the development of generation in a City may offset the need for transmission developments to bring in power from elsewhere, whilst the development of transmission capacity in the area may offset the need for local generation.

[8] Greater transmission capacity within an area will mean that local generators are unconstrained and will also serve to reduce their line losses.

Generation Characteristics

Since electrical energy can be generated in a variety of ways, it is unsurprising that the supply-side of electricity markets is characterized by a wide array of production processes. As a result, suppliers of power will not face a uniform cost structure but instead generating assets will have a wide range of marginal, fixed and sunk costs. For example, coal-fired generation has high fixed and sunk costs but relatively low variable productions costs, whereas peaking gas-fired units have high variable costs but are relatively cheap to build. Because of these cost differences electrical supply functions are not continuous and there can be large price gaps between the prevailing market supply and the price at which additional capacity is available.

An important constraint on the supply-side is that electricity is prohibitively expensive to store. Unlike commodities such as oil and natural gas, the technologies for electricity storage which are currently available, including large industrial batteries and hydroelectric pump storage, are relatively inefficient (i.e. higher cost) in comparison with building additional peaking capacity. In addition, all generation assets face binding capacity constraints in the short-run, strictly limiting the total market supply available at a given point in time. In the long-run, developing new generation capacity is a lengthy process, with short lead-time generators taking upwards of 2 years to build and requiring large capital investments. The market implication of these characteristics is that the competition within electricity markets can vary significantly across time. For example, the market supply function can be extremely inelastic at times of peak demand, when many assets are fully dispatched and are unable to respond to further increases in price.

Given the unique characteristics involved in the production and transmission of electrical energy, the deregulated approach to the supply of power is necessarily distinct from other markets. In particular, the precarious need to ensure system integrity at each point in time, the notable links between generation and transmission, and the important network externalities in transmission, all preclude the ability of a decentralized invisible hand to efficiently coordinate the market. Instead, a very visible System Operator is required to constantly co-ordinate generation, load and the instantaneous flow of power on the grid, according to strict safety and reliability requirements (Wipond (2008)). In addition, given the variation of system load and the short-run constraints on market supply, it is unsurprising that electricity markets can be characterized by fairly extreme price volatility over relatively short periods of time. The unique characteristics of electricity are important in understanding why market power remains a principal concern in deregulated wholesale electricity markets.

1.2 From a Natural Monopoly to a Competitive Market

Prior to the 1990s North American electricity markets were typified by geographic vertically-integrated utilities which were heavily regulated on both the prices charged to consumers and the investments made in generation. These utilities were given exclusive rights to sell electricity to retail consumers in specific franchise areas and were regulated on a cost-of-service basis. Throughout Europe most electricity markets were run by state-owned utilities. The principal economic rationale underlying these regulatory structures was that electricity markets represented a natural monopoly. That is, a single vertically-integrated utility would be able to produce electricity at a lower cost than a number of smaller competing suppliers:

> *"For nearly a century, the electricity sector in all countries has been thought of as a "natural monopoly" industry, where efficient production of electricity required reliance on public or private monopoly suppliers subject to government regulation of prices, entry, service quality and other aspects of firm behavior."* Joskow (1997)

Griffin and Puller (2005) note that the generation, transmission and distribution sectors of electricity markets all had natural monopoly characteristics. In generation, the economies of scale associated with large coal-fired and nuclear plants, coupled with the localized pockets of demand and the substantial line losses from long-distance transmission, meant that generation was an operation efficiently undertaken by a single utility. Similarly, there was, and remains, no rationale for allowing the duplication of transmission and distribution facilities. The scale economies in both sectors prohibit the efficiency of building multiple competing networks.

In addition to the argument of natural monopoly, many economists highlight the theory of transaction costs in explaining the traditional regulated structure of electricity markets. Transaction cost economics posits that one mode of governance will be chosen if it maximizes the net gains from trade. By evolving as a market vertically integrated across generation and transmission, utilities were able to conduct important transactions within a single firm rather than through two firms on the market. The long lives and asset-specific nature of large, sunk investments in generation and transmission implies that transactions between two separate parties are susceptible to opportunistic behavior such as moral-hazard and hold-up.[9] For these reasons, the costs of negotiating and undertaking such delicate transactions can be substantial.

[9] See Bacalso (2000) for an insightful and detailed discussion.

Through vertical integration the market aligns the incentives of the parties and is able to remove these transaction costs.

Another principal attraction of vertical integration is the ability of a single utility to select the supply of electricity that minimizes the total all-in costs. To do this necessitates consideration, and coordination, of the generation and transmission sector costs. Joskow and Schmalensee (1983) contend that the generation sector, in isolation from the transmission network, had not been a natural monopoly market for some time. Instead, they contend that the intrinsic need to vertically integrate the generation sector with the transmission function caused the generation sector to be characterized as a natural monopoly as well.

While the monopolization of electricity markets does have advantages, an unregulated monopolist would have substantial market power. To address this issue, monopoly utilities were regulated on a cost-of-service basis, with the regulator being responsible for approving investments and administering prices. These "bundled" prices were set to cover all operating costs and to allow investors a fair rate-of-return on the capital invested in large sunk and fixed costs. Effectively, prices were set to cover the average cost of supplying electricity.

Beginning with Chile in the 1980s, a growing number of countries around the world have restructured their electricity supply industries to introduce competition into the wholesale and retail sectors (Wolak (2010)). The motivations behind deregulation varied from one region to another, but generally stemmed from the ability to obtain cheaper power, either from generation built by private companies or by buying power from other jurisdictions where prices were low. The frustrations with the existing utility structure were also given additional weight because of

the successful deregulation of other "natural monopoly" markets such as natural gas, telecommunications and airlines.

In addition, technological advancements in high-voltage transmission meant that electrical energy could be efficiently transmitted across long distances with fewer line losses. Meanwhile new Combined Cycle Gas Turbine technology, and falling natural gas prices, meant that generation capacity could now be built efficiently on a lower scale. Both of these advancements undermined the arguments that electricity generation remained a natural monopoly. Finally, the development of sophisticated computer and communications systems, which permitted the real-time monitoring and control of electricity markets, was also an important development in expediting the movement to deregulated wholesale markets.

Economic theory highlights the potential efficiencies to be gained by moving from a market regulated on a cost-of-service basis to one shaped by competitive forces. In particular, the link between prices and costs under traditional cost-of-service regulation provides weak incentives for utilities to achieve lower costs. Church and Ware (2000) explain that if the utility is able to lower its costs, the benefits of cost efficiency accrue to the consumers in the form of lower prices, not to the firm in the form of higher profits. If costs increase, then so do prices, and the firms – or more accurately, their shareholders – continue to earn a pre-specified rate-of-return.

This theory was evident in regulated American power markets as White (1996) and Joskow (1997) highlighted that there were significant variations in performance across utilities, and yet the regulatory structure provided limited opportunities for the efficient utilities to expand at the expense of the inefficient suppliers. White (1996) emphasized that new entrants could build combined-cycle generation assets with average-costs well below those of many incumbent

utilities. As a result there existed a price-gap between generation services embedded in the bundled regulatory prices and the generation services that would be available to the consumers in the wholesale market. A significant amount of this disparity could be explained by the overbuilding of capacity and the development of inefficient generation (most notably nuclear) with large sunk costs that had to be recovered under the regulated regime. Consequently, a large driver behind deregulation in many US states was the potential for lower prices in competitive markets.

> *"While on average real US retail electricity prices fell after 1985, in the Northeast, California, and a few other states, real retail prices continued to rise into the late 1980s and early 1990s as the legacy costs of nuclear plants, combined with excess generating capacity, continued to be reflected in regulated retail prices."*
>
> Joskow in Griffin and Puller (2005)

The unique aspects of electricity markets, however, meant that realizing productive efficiencies in the short-run from deregulation was unlikely. As noted above, a vertically integrated utility is capable of minimizing total costs in the short-run by effectively coordinating generation and transmission. Therefore, there was little motivation to introduce competition into the generation sector in order to minimize short-run costs (Joskow (1996)).

Instead, the principal rationale behind the deregulation of electricity markets was to shift long-run investment decisions regarding new generation away from the regulator and onto the market. The underlying intuition for this is straightforward. Under cost-of-service regulation, once a generation investment is approved by the regulator, the firm is guaranteed to recover its costs. Consequently, a cost-of-service regulation provides few incentives for regulated utilities to invest

efficiently as the risks associated with the investments are inherently placed upon the consumers. If unexpected shifts in supply, demand, energy prices or technology cause the market value of generation investments to decline, the underlying costs remain unchanged and continue to be included in regulated prices. Therefore, regulated prices reflect the current market value of electricity only by accident (Joskow(1997)).

As an example, White (1996) highlights that Californian electricity prices in 1994 were high relative to comparable States due to substantial investments made in nuclear generation that proved imprudent as demand did not grow as forecast, and because natural gas prices declined. By deregulating the generation sector and shifting the risks of large investments in new generation to the market, it is clear that firms will face substantial economic incentives to make such large investments as prudently as possible. In a competitive market, firms also have strong incentives to research and develop innovative generation technologies, furthering dynamic efficiencies. For example, Joskow (1997) contends that the development of Combined Cycle Gas Turbines technology was a direct result of the Public Utilities Regulated Policies Act ('PURPA'). A key component of PURPA was that it allowed independent energy companies to sell their power to the utilities, at a price based on the utility's avoided costs. Therefore, independent power suppliers with low cost generation could profitably enter the integrated US markets. This Act is seen by many as the beginnings of deregulation in North American power markets.

1.3 What is Market Power?

Supplier market power is defined as the ability of a supplier to profitably move market prices above the competitive level. In other words, a supplier has market power if it finds it profitable to raise the market price above its marginal cost of production (Church and Ware (2000)). Any supplier facing a downward sloping demand function will have market power and will maximize profits by realizing that it faces a price-volume trade-off; by selling less output the firm can realize a higher price on the output that is sold. In recognizing that its output decision has an impact on the market clearing price, the supplier will optimally lower output below the competitive level and raise the market price to maximize profits.

As an example of market power, suppose that a generator has 1,000 MW of capacity for sale in the hourly power pool. If the generator runs all of its capacity the hourly pool price will settle at $70. If the generator economically withholds 200 MW of generation by offering this capacity at high prices, the pool price is raised from $70 to $100. By supplying 800 MW rather than 1,000 MW the generator is able to increase the price and, by doing so, is able to increase revenues from ($70 x 1000) = $70,000 to ($100 x 800) = $80,000. In addition the generator is able to avoid the costs associated with running the 200 MW of capacity that is economically withheld. Assuming the avoided variable costs are $15/MWh, the generator is able to save $3,000. In this example then, the exercise of market power increases variable profits by $13,000.

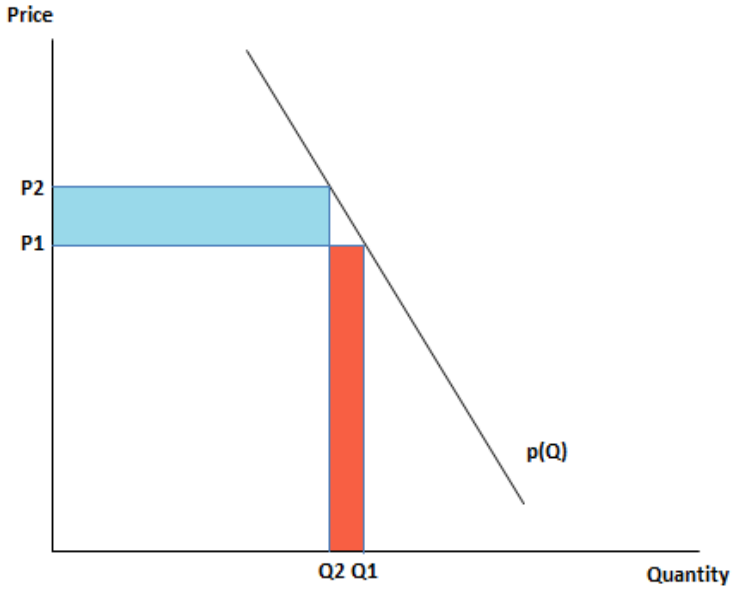
Fundamentally, the profitability of exercising market power depends upon the firm realizing a sufficient revenue gain on its exposure to the pool price relative to the margins that are foregone on the generation that is withheld. In the above example, the firm is able to increase revenues on the 800 MW sold by a total of ($100 - $70) * 800 = $24,000. However, the firm foregoes the

opportunity to obtain the margins associated with the 200 MW of generation that is withheld: ($70 - $15) * 200 = $11,000. Since the gain of $24,000 exceeds the $11,000 that is foregone, the strategy is profitable.

To highlight this concept generally, consider a monopolist supplier that must sell its product at a uniform price. Since the firm's demand function is downward sloping, the price the firm attains for its product depends upon the quantity sold, so by reducing supply the firm is able to charge a higher price for the output that it does sell (the inframarginal output). Therefore, by reducing output the firm can potentially increase profits because the inframarginal units are now sold at a higher price. Counteracting this, the firm will incur a loss in revenue at the margin because less output is being sold. If the gain on the inframarginal units exceeds the loss at the margin, the firm can increase its profits by reducing output.

This intuition is illustrated in Figure 2 where, for simplicity, variable costs are assumed to be $0). By reducing supply from Q1 to Q2 the monopolist is able to increase the market price from P1 to P2. As a result of this price increase, the firm increases revenues earned on the inframarginal output (the blue shaded area). However, the firm also suffers a loss in revenues at the margin because the output (Q1 – Q2) is no longer supplied (the red area).

Figure 2: Marginal Revenue – the inframarginal gain vs. the marginal loss



In this way, any firm facing a downward sloping demand function will have two components to its marginal revenue. By increasing its output by a single unit the firm obtains an increase in revenues equal to the market price (p). However, by selling the additional unit the firm will lower the market price (by $\frac{\partial p}{\partial q}$) and so the firm suffers a loss in revenues on the inframarginal output (q). Hence, the firm's marginal revenue function is given by:

$$MR = p + \frac{\partial p}{\partial q} q$$

The firm maximizes profits by producing the quantity of output for which the marginal revenue of the last additional unit equals the marginal costs of producing that unit (*MC*):

$$p + \frac{\partial p}{\partial q} q = MC$$

Re-arranging the above equation yields the following profit-maximizing condition for a monopolist supplier. Here ε denotes the elasticity of demand, which quantifies how responsive demand is to changes in price. The elasticity of demand is calculated as the percentage change in quantity demanded divided by the percentage change in price ($\varepsilon = \frac{\partial q}{\partial p}\frac{p}{q}$).

$$\frac{p - MC}{p} = \frac{1}{|\varepsilon|}$$

The left-hand side of this equation shows the extent to which the market price exceeds marginal costs. Higher values of the Lerner Index indicate a higher price-cost mark-up, which implies greater market power. The right-hand side of the equation is the inverse of the elasticity of the market demand function. The implication here then is that as the market demand function becomes increasingly inelastic (i.e. becomes less responsive to price changes), the market power of the monopoly supplier is increased.

This simple economic theory can also be applied to a firm that faces a downward sloping *residual demand* function. A firm's residual demand function *(RD(p))* is defined as the market demand *(MD(p))* remaining to be served by that participant after the supply of all other participants *(QSO(p))* has been subtracted out. A firm's residual demand function shows its sales for any price that the firm charges.

$$RD(p) = MD(p) - QSO(p)$$

Following the same logic as above yields the following profit-maximizing condition for a firm facing the residual demand function *RD(p)*:

$$\frac{p - mc}{p} = \frac{1}{|\varepsilon_{RD}|}$$

Where ε_{RD} is the elasticity of the firm's residual demand function ($\varepsilon_{RD} = \frac{\partial RD}{\partial p}\frac{p}{RD}$).

Since the firm's residual demand is a function of market demand and the supply of other firms, the elasticity of the firm's residual demand will depend upon the elasticity of market demand and the ability of other firms to respond to changes in price. In particular, this profit maximization condition highlights that the market power of a firm facing a downward sloping residual demand function will decrease as consumers become increasingly able to substitute away from the underlying good (demand-side substitution), or if consumers can readily substitute to an alternative supplier of the same good (supply-side substitution).

1.4 Market Power in Wholesale Electricity Markets

Experience with electricity markets, most notably the California energy crisis of 2000-2001, has shown that supplier market power is a principal issue in deregulated electricity markets:

> *"It is difficult to conceive of an industry more susceptible to the exercise of unilateral market power than wholesale electricity; it possesses virtually all of the product characteristics that enhance the ability of suppliers to exercise unilateral market power."*
>
> Wolak (2009)

When discussing market power in wholesale electricity markets, researchers often distinguish between the economic withholding and the physical withholding of capacity. That is, a generator can reduce its supply by offering generation at high prices (economic withholding) or by

withholding the capacity from the market completely (physical withholding). In the Alberta power pool, the physical withholding of output is prohibited, and each asset must offer all available capacity into the market. However, the economic withholding of generation is not prohibited within the Alberta legislation.[10] This is consistent with Alberta's 'energy-only' market design, where the exercise of market power is arguably necessary to allow incumbent firms to recover fixed and sunk costs and to incentivise investment in new generation capacity (see section 3.1 for further discussion).

As highlighted above, any firm facing a downward sloping demand curve will have market power. Therefore, in a practical sense market power does not normally warrant anti-trust concerns. Market power is a concern only to the extent that it is both significant (prices exceed not only marginal costs, but long-run average costs) and durable (the firm is able to maintain these high prices). For example, the Canadian Competition Bureau defines unilateral market power as:

> *"A unilateral exercise of market power occurs when the merged firm can profitably sustain a material price increase without effective discipline from competitive responses by rivals."*[11]

1.4.1 Demand-Side Substitution

The ability and willingness of consumers to substitute away from the underlying product will have an important impact upon the market power of suppliers. The responsiveness of consumers to changes in a products price is measured by the elasticity of its demand. The demand for a

[10] See the *FEOC Regulation* and the Alberta MSA Offer Behaviour Enforcement Guidelines.

[11] See paragraph 6.10 on page 21 of Merger Enforcement Guidelines

product becomes increasingly inelastic as consumers become less responsive to changes in its price. This is an important consideration for supplier market power because as demand becomes more inelastic, suppliers will face a lower fall in demand when prices rise, so the unilateral market power of suppliers increases. The market demand for electricity is almost perfectly inelastic in the short-run, meaning that demand is almost completely unresponsive to changes in the real-time price for electricity. This is because:

- Most residential and small electricity consumers do not face (or know) the real-time price of electricity and therefore have no incentive (or ability) to reduce consumption when real-time prices spike.
- For the vast majority of large industrial consumers that are exposed to real-time prices, electricity is a necessity. For these firms, reducing power consumption will require curbing an industrial process which is usually very costly.
- Consequenty, most consumers of electricity have a very high willingness to pay. In the event of a supply-shortfall the system operator must ration demand by shedding load. In this case, the value of another megawatt-hour of power equals the cost imposed by the involuntary load curtailment. This is defined as the Value Of Lost Load ('VOLL') (Stoft (2002)). Estimates of VOLL are generally upwards of $10,000/MWh. Most markets have a price cap that is well below this figure (in Alberta the price cap is $1,000/MWh) so this limits the demand-side response to price changes.

1.4.2 Supply-Side Substitution

As highlighted the discussions in section 1.1, electricity is a unique commodity. Many of these unique characteristics will limit the extent of supply-side substitution and therefore increase the ability of suppliers to exercise unilateral market power.

Unlike other commodities, electrical power cannot be stored economically. This means that generators are unable to build inventories of electricity when prices are low in anticipation of profitable prices in the future. As a consequence, suppliers will face less supply-side substitution in comparison with other commodity markets.

Suppliers of electricity are also subject to meaningful capacity constraints in the short run and generators cannot increase supply beyond these constraints. The lack of storage and the inability of suppliers to increase generation beyond physical capacity limits together mean that when market conditions are tight, the extent of supply-side substitution can be notably limited. Therefore, when the market's available supply is almost exhausted, a firm withholding a small amount of output can have a substantial impact on the prices, so the exercise of market power can be a very profitable strategy for suppliers when the market is tight.

Transmission constraints can also be an important factor in determining the extent of short-run competition in power markets. Congestion occurs when generation assets within a constrained area are limited in their ability to supply power to load pockets outside of this area. Therefore, in the event of congestion the extent of supply-side substitution outside of the congested area is limited. The inability of the congested generators to supply demand outside of the constrained area will increase the market power of assets in the unconstrained areas. Depending on the

market rules, this could inflate prices in the unconstrained areas, or prices throughout the market (i.e. in both the constrained and unconstrained areas).[12]

Finally, because of offer rules and because electricity can be produced using a wide array of technologies, the supply-of-other-firms function will be a discrete step function. That is, sections of this supply function are perfectly inelastic, indicating that competing firms are unable or unwilling to alter their supply between two prices. When the market clears underneath a step that is vertically large, firms can increase the market clearing price by withholding a minimal amount of generation and their ability to exercise unilateral market power is clear in these cases.

1.4.3 Long-Run Considerations

The development of new electrical generating capacity is characterized by large sunk capital investments, meaningful fixed costs and long-lead times. For example, to bring a 50 MW peaking gas-unit online will take around 3 years and will typically require investing over $50 million. Once online, the plant's fixed operational and maintenance costs will be around ~$650,000 a year. For baseload coal units, the initial capital investments are in the region of $1.5 billion, with coal units taking upwards of 4 years to build. Recent estimates for the fixed O & M costs on newer coal-fired units are ~$14.2 million a year in Alberta.[13] It is clear then that wholesale electricity markets are an industry characterized by economies of scale and large sunk costs. These characteristics are an important consideration when discussing market power in the Alberta electricity industry.

[12] For a discussion of the treatment of congestion in the Alberta power pool see the submissions for AUC proceeding 1790.

[13] Cost estimates obtained from AESO (2012) Long Term Outlook at Appendix H

In particular, the economic model developed by Cournot highlights that a certain degree of market power is to be expected in industries characterized by large capital investments and fixed costs, as this market power is needed for firms to recover their capital investments and fixed costs. The Cournot model explains that new entry will only occur if the entrant believes that post-entry prices will be sufficient to cover the long-run average costs of its operations. In a competitive market, the process of entry and exit should occur until no other generator could enter the market place and expect to recover its investment costs at the post-entry market prices.[14] In other words, new entry should occur up until market power becomes insufficient to warrant further entry.

As a result a finding of market power requires (i) evidence of the short term exercise of market power that is material and (ii) a further check that the quasi rents (i.e. profits) earned from that exercise exceeds the fixed and sunk costs of entry. For small increments of additional supply, the profitability of entry can be assessed by assuming entry would have no impact on prices. For large increments of supply, the analysis should consider the effect on quasi rents of entry. The comparison would then be between the adjusted quasi rents and the fixed costs of entry. In summary, a finding of market power would require evidence, along these lines, that new entry is profitable but it is not realized.[15]

1.5 Market Power and Economic Efficiency

In most markets, a major concern with the exercise of unilateral market power is the resulting deadweight loss (i.e. or allocative inefficiency). Allocative inefficiencies arise when it is

[14] See Church and Ware (2000) at section 8.2.3 'Free-Entry Cournot Equilibrium'

[15] See the MSA's 2012 report "A Comparison of the Long-Run Marginal Cost and the Price of Electricity in Alberta" for a recent and relevant discussion of these issues.

possible for both a consumer and producer to gain by additional trade. The exercise of market power means that units of output for which the value to consumers exceeds marginal cost of production are not traded. As a result the exercise of market power creates an opportunity cost to society called the deadweight loss (Church and Ware (2000)).

In wholesale electricity markets the inelasticity of short-run demand means that increasing the market price will have almost no effect upon the quantity consumed. In addition, the Alberta market has a price cap of $1,000/MWh and only around 200 MWh of demand responds to real-time prices (see section 3.3). Consequently, the deadweight loss associated with the exercise of market power is relatively small and allocative inefficiencies, at least in the short-run, are not a principal concern with the exercise of unilateral market power.

Instead, the primary concern with the exercise of market power in electricity markets is the potential for significant transfers of wealth from consumers to producers in a short period of time. The potential extent of this issue was emphatically demonstrated during the California energy crisis:

> *"Starting in June 2000, California's wholesale electricity prices increased to unprecedented levels. The June 2000 average of $143 per megawatt-hour (MWh) was more than twice as high as in any previous month since the market opened in April 1998. These high prices produced enormous profits for generating companies and financial crises for the regulated utilities that were required to buy power in the wholesale markets and sell at much lower regulated prices in the retail markets. The state's largest utility, Pacific Gas & Electric, declared bankruptcy in March 2001. The state of California took over wholesale electricity purchases and spent more than $1 billion per month buying power in the spring of 2001, with average prices more than ten times higher than they had been a year earlier. Accusations of price gouging and collusion among the sellers*

> *were widespread. Some observers blamed the problems on the format of the wholesale auctions in California, while others focused on the way that transmission capacity is priced and how prices varied by location. A number of economists, myself included, did studies that concluded that sellers exercised significant market power."*
>
> Borenstein (2002)

As well as the potential for significant wealth transfers, the exercise of unilateral market power may also cause productive inefficiencies in the supply of electricity. Productive efficiency is achieved when the total costs for a given level of output at a particular point in time are minimized. In terms of market power, the withholding of generation capacity that has relatively low costs will cause production to be reallocated to assets with higher costs, thereby causing productive inefficiencies compared with the competitive market. As an example, Wolak and Patrick (1997) show that coal-fired plants owned by the UKs two largest generating companies often went on outage when the firms were able to substantially raise the market price. In order to meet demand, the output of the coal plants was replaced by combined-cycle gas turbine generators, which had higher production costs.

It is important to highlight that allocative and productive efficiency are both static measures. These measures are static because they refer to achieving market efficiencies at a particular point in time. As discussed previously the deregulation of electricity markets was not driven by such short-run concepts but was instead motivated by the potential for achieving long-run dynamic efficiencies, which are fundamentally driven by shifting generation investment decisions away from the regulator and onto the market. In this context, the principal concern is that firms exercising unilateral market power may distort the long-run price signal. The price signal from the electricity market is critical for both generators and consumers to make efficient decisions.

On the generation side, investors rely on the market price signal to inform new investments in generation capacity. If the price signal is driven upwards by the exercise of market power rather than by economic scarcity, there is the potential that investors will over-build, bringing on additional generation capacity when the efficient use of existing capacity is optimal (Wipond (2008)). On the other hand, investors may be reluctant to develop new capacity if they believe that the market price signals are significantly controlled by the actions of incumbent generators.

On the load side, the continual inflation of wholesale prices will inevitably mean that consumers of electricity will face higher (fixed) rates. In the long-run then, market power can motivate loads to make inefficient choices in order to reduce consumption of electricity. For example the exercise of market power may prevent investment in productive enterprises that require substantial electricity use and can lead to inefficient substitutions away from electricity to other inputs (Borenstein, Bushnell and Wolak (2002)).

Chapter 2: The History of Alberta's Electricity Market

The purpose of this section is to document the deregulatory process undertaken in Alberta. Since the focus of this thesis is on analyzing the Alberta wholesale market in more recent times, particular attention is paid to wholesale market developments that were significant and remain relevant in the wholesale market today.

2.1 The Regulated Market and the Motivations for Deregulation

Prior to its deregulation the Alberta electricity industry was dominated by three large vertically-integrated utilities. The largest of these was TransAlta, an investor owned utility which operated approximately 50% of Alberta's 8,600 MW generation capacity. Alberta Power (ATCO), also investor-owned, operated slightly less than 20%, while Edmonton Power (later EPCOR), a city-owned utility, ran slightly more than 20%. The three firms operated a total of 50 generation assets, 75% of which were coal based with the remaining 25% being about evenly split between natural gas fired plants and hydro units (Daniel (2003)).

All three utilities operated as franchise monopolies under a cost-of-service regulation framework. Under this framework, each firm had a de facto right to provide power within its own franchise area. The Transmission system was almost entirely owned by the three major utilities, and they supplied electricity to their own franchise areas as well as to municipal utilities. As well as being regulated on the prices charged, the firms were heavily regulated on their investments. For a facility to be developed the utilities had to convince the regulator that it was required, and utilities did not have the authority to decide whether new generation or new transmission was needed to serve future demand. Once a new facility was approved by the regulator, it was

included in the utility rates, which were set based on approved costs and on the utilities earning a reasonable rate of return on their sunk capital. Electricity prices were set to cover these and other service costs, so effectively prices were set equal to the average cost of providing electricity.

Within this framework utilities faced very little risk when developing new electrical facilities, indeed their incentive was to overdevelop in order to earn the regulated rate-of-return on the costs incurred. As a result, the regulatory structure led to inefficiencies. At the plant level, generators were often seen as 'gold plated' as utilities weren't shy about incurring costs which would almost certainly be recovered.

At a broader level, the market design also caused significant investment inefficiencies. For example, in the late 1970s, a time of consistent economic growth, the three utilities each received approval to construct new generation facilities. After the approval of the regulators, but before construction begun, commodity prices and the Alberta economy collapsed. Despite this, construction of the generators went ahead as scheduled because the utilities had no incentive to respond to these price signals under the regulated regime. With the completion of the last regulated plants in the 1980s, Alberta had an expensive surplus of generation supply (Nicolay (2011)).

The existing regulatory structure also received criticism from the utilities. In particular, the Alberta Electric Energy Marketing Act (EMMA) was heavily criticized. The EMMA had been established in 1982 to equate electricity prices across the province. Under this Act, utilities were required to sell their power to the Alberta Electrical Energy Marketing Agency which then sold power at a uniform (or 'pooled') rate to distributors. Consequently, the only price differentials

across the province were due to differences in distribution costs. This regime was criticized by TransAlta as subsidising relatively expensive generation being developed in the North of the province. The resulting review of the EEMA, initiated in 1992, resulted in reforms introduced by the 1995 Electrical Utilities Act (EUA). The EUA came into effect in January 1996 and was the first formal step in the process of restructuring Alberta's power market.

While the regulatory regime that was in place prior to this time was far from perfect, it is worth documenting that high costs were not a principal factor in the deregulation of Alberta's electricity market. Electricity prices were low and service delivery was reliable under the regulated regime. In fact, it was recognized that new gas-fueled generation was likely to involve higher average costs than the embedded coal-fired generation, and the prospect of reducing electricity prices in the short-run was not a driver behind the Alberta restructuring initiative. Instead the principal drivers behind the deregulation of Alberta's power market were to 'streamline' (i.e. reduce the costs of) regulation and to shift the generation investment decisions away from regulatory court hearings and onto the market (Wipond (2008)). More broadly, the improvements in transmission and the development of Combined Cycle Gas Turbines technology, in combination with the successful deregulation of other natural monopoly industries, meant that policy-makers in Alberta were able to turn to a markets-based approach for developing electrical generation capacity. This markets-based approach is consistent with the principles and beliefs of policy-makers and the business community within Alberta, and these ideologies were also a factor in the decision to deregulate.

2.2 The Electric Utilities Act (1995) and Legislated Hedges

The EUA (1995) was the first formal step in the process of restructuring Alberta's electricity market. The Act established a Power Pool through which all electricity in the province would flow, and a Transmission Administrator that provided open access to transmission facilities. Offers to supply power into the Pool and bids to purchase power from the Pool would determine, on an hourly basis, the wholesale market price of electricity. A central component of the initial market was a set of Legislated Hedges. These hedges were intended to mitigate the exercise of market power by the three incumbent utilities, and to protect existing retail customers and regulated generation units from the new Pool Price (Daniel (2003)). To do this the legislated hedges provided a contract-for-differences which insulated existing generation and existing retail demand from the new Pool Price, and only new generation and new loads were exposed. Consequently, pre-existing generation and load effectively remained regulated as distribution companies and the Transmission Administrator continued to pay the regulator-approved fixed and variable costs to the generation owners (Bacalso (2000)).

One of the major issues faced by early policy-makers was a concern that the deregulated market would not provide sufficient incentives for firms to invest in new generation capacity. This issue was notable in Alberta because of the low costs of the embedded generation and a healthy capacity margin prior to deregulation. Overall, the expectation was that pool prices would initially be uneconomical for new investment, but that prices would rise sufficiently over time as market demand increased. However, these price rises failed to materialize and pool prices remained low even though the market tightened substantially between 1996 and 2000 as the Alberta economy grew faster than expected.

In a study for the Alberta government, London Economics (1998) found that market prices were being distorted downwards by the Legislated Hedges, and that this was deterring new entry into the market. Specifically, London Economics noted that the incumbent utilities were immune to low pool prices and were incented to offer their generation into the market at variable cost because of the Legislated Hedges. Therefore, one effect of the Legislated Hedges was to keep Pool Prices well below the average-costs of new merchant gas-fired generation. Other authors (Daniel et. al (2003)) ascribe uncertainty regarding the path of deregulation as the key reason for the lack of additional generation capacity.

2.3 The Electric Utilities Act (1998) and Power Purchase Arrangements

A desire to accelerate the movement to a competitive market, combined with the noted shortcomings in the initial EUA, led to the Electrical Utilities Amendment Act (EUAAA) of 1998. The amendment included steps leading to the elimination of the Legislated Hedges, reduced generator concentration through Power Purchase Arrangements ("PPAs"), the establishment of the Market Surveillance Administrator ("MSA"), and also outlined a plan for retail competition by 2001 (Wipond (2008)).

The introduction of the PPAs in 2001 was a major factor in the deregulation of the Alberta market and the PPAs will continue to be an important component in the Alberta Power Pool until December 31st of 2020. At present, 5,000 MW of coal-fired capacity and 800 MW of Hydro generation remains under a PPA. The PPAs were designed to deal with the two key issues that the Legislated Hedges had merely glossed-over; market power and stranded benefits.

In terms of market power, simply deregulating the generation sector as it stood was not a viable option because the existing structure was highly concentrated. To increase market competition the Alberta government legislated that incumbent utilities had to sell the rights to the electricity generated from their power plants. The sale of these rights took place in August 2000 at a one-time ascending bid auction. Beginning on January 1st 2001, the PPA contracts were specified to a length of 20 years, or until the end of the plants life if that was sooner (see Table 1). In total, the rights to 6,250 MW of thermal capacity were put up for sale at the initial PPA auction and 4,100 MW were sold.[16] In addition, 790 MW of Hydro capacity was put under a financial PPA, which is discussed in more detail shortly. To ensure the market was more competitive post-auction, the government placed strict limits on purchases and no one participant was allowed to control more than 20% of the market capacity (Williams (2002)).

The PPAs were a 'virtual divestiture' since the incumbent utilities (the PPA Owner) still own and operate the generation assets which they built under regulation, however the electrical capacity is marketed by a different firm (the PPA Buyer). The PPA Buyer compensates the Owner for the energy according to the terms of the PPA, and it is the PPA Buyer that receives the revenues from the energy sales. Consequently, it is the PPA Buyer that incurs any profits or losses that result from the sale of electricity into the power pool.

[16] The Genesee, Sheerness and Cloverbar PPAs were not sold at the initial auction.

Table 1: PPAs – Capacity, Retirements and Term Dates

PPA	PPA Owner	Fuel Type	Units	Capacity	End of Term	Retired
Battle River	ATCO	Coal	BR3	147.3	Dec-31-2013	
			BR4	147.3	Dec-31-2013	
			BR5	368.2	Dec-31-2020	
Clover Bar	EPCOR	Gas	CG1	157.3	Jan-01-2011	2005
			CG2	157.3	Jan-01-2011	2005
			CG3	157.3	Jan-01-2011	2005
			CG4	157.3	Jan-01-2011	2005
Genesee	EPCOR (Capital Power)	Coal	GN1	381	Dec-31-2020	
			GN2	381	Dec-31-2020	
HR Milner	ATCO	Coal	HRM	144.3	Jan-01-2013	
Hydro	TransAlta	Hydro	BOW1	320	Dec-31-2020	
			BRA	350	Dec-31-2020	
			BIG	120	Dec-31-202	
Keephills	TransAlta	Coal	KH1	383	Dec-31-2020	
			KH2	383	Dec-31-2020	
Rossdale	EPCOR	Gas	RG8	64 (Summ), 67 (Wint)	Dec-31-2003	2004
			RG9	67 (Summ), 70 (Wint)	Dec-31-2003	2004
			RG10	67 (Summ), 70 (Wint)	Dec-31-2003	2004
Rainbow	ATCO	Gas	RB1	29.5	Dec-31-2005	2012
			RB2	43.5	Dec-31-2005	2012
			RB3	19.5	Dec-31-2005	2012
Sturgeon	ATCO	Gas	ST1	10	Dec-31-2005	2012
			ST2	8	Dec-31-2005	2012
Sheerness	ATCO (50%) TransAlta (50%)	Coal	SH1	378.1	Dec-31-2020	
			SH2	378.1	Dec-31-2020	
Sundance A	TransAlta	Coal	SD1	280	Dec-31-2020	
			SD2	280	Dec-31-2020	
Sundance B	TransAlta	Coal	SD3	353	Dec-31-2020	
			SD4	353	Dec-31-2020	
Sundance C	TransAlta	Coal	SD5	353	Dec-31-2020	
			SD6	357	Dec-31-2020	
Wabamum	TransAlta	Coal	WB1	65	Jan-01-2004	Dec-2004
			WB2	65	Jan-01-2004	Dec-2004
			WB3	139.3	Jan-01-2004	Nov-2002
			WB4	278.6	Jan-01-2004	Mar-2010

The PPA contracts were tailored to keep the payments flowing to the PPA Owner consistent with those they would have been received under regulation. In particular, the contracts specify variable energy payments as well as monthly fixed capacity payments to be made from the Buyer to the Owner. These payments were approved by regulators and were based on a calculation of expected costs and a reasonable rate of return for the Owners (Bacalso (2000)).

The PPA contracts are also structured to incentivise the PPA Owners to strive for operational efficiency and maximum availability. Two of these "Availability Incentives" are notable. First, the PPA Owner retains the rights to any electricity that is available beyond the capacity covered in the PPA. As a result, the offer control over energy generated from a PPA plant is often split between Owner and Buyer, with the Buyer controlling the unit's Committed Capacity and the Owner controlling any Excess Energy or Increased Capacity (see section 3.4 for further discussion). Secondly, the PPAs specify an hourly Availability Incentive Payment (AIP) under which the Owner is rewarded for increased availability and punished for a lack of availability by means of a financial settlement with the PPA Buyer. These availability payments can be significant when generation units are unavailable during times of high 30-day rolling-average prices. Consequently, the timing of outages at a PPA asset can meaningfully effect the profitability of the asset for both Owner and Buyer, and the scheduling of outages will also impact their incentives to exercise market power (see section 5.3.3 for a detailed discussion).

In terms of dealing with structural market power, the PPAs were relatively successful in reducing the concentration of the generation capacity within the province. By dividing 90% of the existing generation that was in the hands of the three main incumbents into fourteen PPAs,

Alberta achieved a significant increase in the competitiveness of the generation sector (Wipond (2008)).

The PPAs auctions were also designed to deal with the issue of 'stranded value'. In the process of deregulation, the issue of stranded value arises because the value of a generating asset in a competitive market environment can vary considerably from its value under regulation. An asset which is worth more in the deregulated market is said to have stranded benefits, while an asset which is worth less after deregulation is said to be left with stranded costs.

Most of the embedded assets in Alberta were viewed to have stranded benefits since the majority of their fixed costs had already been recovered under regulation and because market prices were expected to exceed their variable costs in the future. Therefore, these PPAs were expected to sell at fairly high prices. On the other hand, some of the newer plants had high fixed capacity charges attached to them and these PPAs were expected to be sold at negative prices (Sheerness and Genesee).

Overall, the expectation was that the sum of winning bids in the auction would be substantial and would approximate the present market value of the generation asset investments made under the regulated regime. The province of Alberta was to retain these stranded benefits and the proceeds of the PPA auctions were distributed to consumers in the form of rebates. However, the initial auctions were not overly competitive, with approximately the same number of bidding firms as the number of PPA contracts available (although firms were allowed to bid on more than one PPA). In addition, the prospective buyers likely discounted the potential market value of these assets because of the significant amount of risk and uncertainty involved in trying to specify a

20-year contract involving vast sums of capital each year.[17] Consequently the auctions generated considerably less revenues than had been anticipated and the initial PPA auctions were unsuccessful in terms of obtaining the stranded benefits of the embedded generation capacity (Hollis (2006)).

To help manage the PPAs and the deregulation process, the Balancing Pool was created under the umbrella of the Power Pool with a mandate to assist in the transition to a fully competitive generation market and to ensure that Albertans received the financial benefits associated with the restructuring process (i.e. the stranded benefits). The Balancing Pool was also tasked with being the Buyer for the Hydro PPA. The typical Owner-Buyer relationship was deemed to be unfeasible for the Hydro units given the intricacies involved in their operations. The offer control for the Hydro units remains with the PPA Owner (TransAlta), but the Owner has financial Energy and Reserve obligations which are paid to the Balancing Pool. The volumes of these obligations were set based on historical water flows and vary across hours of the day, between winter and summer seasons, and from weekdays to weekends. The financial payments from Owner to Buyer are based on these committed volumes and on realized hourly prices.

After the Sheerness, Genesee and Cloverbar PPAs failed to sell in the initial auction the duties of the Balancing Pool were expanded. As well as managing the Hydro PPA the Balancing Pool took over management of these three assets with a mandate to maximize the value of these assets, whilst helping to transition the market towards deregulation. The balancing pool held two Market Achievement Plan ("MAP") auctions, one in December 2000 and one in 2002-2003, in which the energy rights for the unsold PPAs were sold in strips (AESO (2006)). In 2005 the

[17] For instance, Bacalso (2000) notes "As a long term contract the PPA will be necessarily incomplete and will be unable to align the interests of the parties to the PPA. Subsequently, the PPA will be unable to mitigate opportunistic activities within the transaction. This inability will erode the expected gains from the PPA exchange."

original Cloverbar units were returned to EPCOR and the units were decommissioned later that year. The Sheerness PPA was sold by the Balancing Pool in November 2005 with TransCanada winning the auction at $585 million and obtaining the energy rights for these units beginning in 2006.[18] The Balancing Pool remains the PPA Buyer for the Genesee units.

2.4 The Electric Utilities Act (2003) and the Alberta Utilities Commission Act (2007)

Following an extensive review of the electricity market structure beginning in February 2000, the Alberta government proclaimed the Electric Utilities Act (EUA) of 2003, which instituted a number of changes to the regulatory framework of the Alberta market. The Act combined the Transmission Administrator, the System Controller and the Power Pool into the Alberta Electric System Operator (AESO). The AESO is an independent, non-for profit agency responsible for the real-time operation of the Alberta Power Pool, as well as the long-term planning and development of the Alberta Interconnected Electric System (AIES). The role of the AESO regarding transmission development was further clarified in 2004 when the government of Alberta published a new Transmission Policy. This Policy also reiterated a commitment to postage-stamp tolling for transmission and addressed issues around the use of interties and transmission must run generation.

The EUA of 2003 also specified that the Alberta MSA and the Balancing Pool were to be split from the Power Pool (now the AESO) to provide these organizations with greater independence. This structural change was notable for the MSA whose mandate was seen in conflict with the pre-existing structure, and the organization remains responsible for ensuring the market operates

[18] To get an idea of how the value of these assets had changed since 2001, recall that the Sheerness PPA failed to sell at all and had been expected to sell for a negative value at the initial PPA auction.

in a fair, efficient and openly competitive manner. Part of this mandate includes scrutiny of AESO policies, operations and ISO rule developments.

In 2004 and 2005 the Alberta government led another round of consultations focused on the structure of the Alberta market. The Department of Energy's policy paper of June 2005 summarized the results of more than a year's worth of market review, stakeholder consultation and public discussion (see DOE (2005)). As a result of these discussions, the DOE published papers in November 2005 and April 2006 to clarify the roles and mandates of the regulating bodies governing the Alberta electricity market. The policy papers clarified that the AESO's principal responsibility is the reliable operation of the Alberta electrical system; the MSA's mandate was listed as a 'watchdog' to ensure fairness, efficiency and open competition and to deal with major ISO rule breaches; the principal roles of the EUB in the electricity market were listed to be the market's adjudicator and to regulate the development of the transmission system and distribution networks.

The regulatory structure of the Alberta market was modified slightly again in 2007 with the introduction of the Alberta Utilities Commission Act (AUCA) which came into effect on January 1st 2008. The principal change made by the AUCA was to split the EUB into the Alberta Utilities Commission (AUC) and the Energy Resources Conservation Board (ERCB). Under this act, the ERCB was tasked with regulating the development of Alberta's oil, natural gas, oil sands, coal and pipelines, whilst the AUC was given the EUB's roles within the electricity sector. Under AUCA, the AUC is usefully viewed as the electricity market's adjudicator for a broad range of issues:

> *The AUC has the responsibility to provide the adjudicative function with respect to the contravention of specific electric and gas utilities legislation; AUC Decisions and Orders; ISO Rules; as well as agency and market participant conduct. The AUC also hears objections and complaints regarding market rules and standards.*
>
> AUC Website

In addition, the AUC is responsible for regulating and approving the development Alberta's transmission system and new generation capacity must obtain AUC approval regarding the siting of its facilities, and their impact on the local communities, before being built.

In addition, the AUCA modified the regulatory structure regarding ISO rule contraventions. Previously, contraventions of ISO rules had been the sole responsibility of the AESO, and the MSA would only be involved if the rule breach was seen as a 'significant contravention'. However, this was viewed as imprudent because the AESO was both the creator and enforcer of the ISO Rules. Consequently, the Act specified that the roles of the ISO rules maker (the AESO), the ISO rules enforcer (the MSA), and the ISO Rules adjudicator (the AUC) would be independent of one another going forward.

2.5 Recent ISO Rule Developments

The policy framework documented by the DOE in June 2005 mandated that the AESO modify the market structure in response to the perceived shortcomings outlined in the review (Alberta DOE (2005)). Consequently, the AESO implemented an integrated package of market design changes on December 3rd 2007, which were identified as the 'Quick Hits' rule changes (AESO

(2009)). These rule changes remain an important component of the Alberta market's operations today.

2.5.1 'T-2' and Must Offer Rules

One of the recommendations made by the DOE was to reduce the volatility of offer restatements immediately prior to and during the settlement hour. Consequently a series of changes were made to stabilize the market merit order two hours prior to the settlement hour. The first change, referred to as "Must Offer / Must Comply", requires generators to offer all of their generation capacity into the market or else provide an Acceptable Operating Reason as to why the total generation is not being offered (ISO Rule 3.5.3 c)). Previously generators had been allowed to offer a subset of their actual capacity and then revise their offers at a later time if market conditions were favourable.

The second change was to shift gate closure forward from noon the previous day to 2 hours prior to the impacted settlement period. This 'T-2' policy allows generators in Alberta to alter their offer strategies as many times as they want prior to 2 hours before the start of the settlement hour.[19] For instance, for Hour Ending 19 (18:00 - 19:00) a generator can submit an unlimited number of offer changes ("Voluntary Price Restatements") before 16:00.[20]

[19] Strictly speaking participants are still required to submit an offer by noon of each day for the next six trading days. However these can be changed at any time prior to T-2 so they are of little relevance.

[20] Previously, generators submitted all of their offers day-ahead and were allowed to make one 'Locking Restatement' per generation asset per trading day to alter these day-ahead offers. These Locking Restatements allowed for a complete reallocation of energy offered in each hour across the various price blocks that make up the hourly offers submitted day-ahead. That is, although the prices of each block within each hourly offer had to remain as originally offered day ahead, the amounts of energy offered in each block could be changed. Locking Restatements were permitted up to 'T-30' without an operational reason (Wipond (2008)).

To be specific, the Voluntary Energy Restatement rules allow generators to alter the *distribution* of the price-quantity offers, but they do not provide a mechanism for participants to alter the total amount of energy being declared available. Within the T-2 window an offer can only be altered due to operational reasons. To inform the AESO of a change in the unit's Available Capability, participants must submit a Mandatory Energy Restatement (Rule 3.5.3.2). These restatements can be made at any time, including within the T-2 window.

In summary, the T-2 changes have increased the flexibility of generators to alter their offers in response to market changes that occur prior to the T-2 gate closure, but have removed their ability to revise offers within the T-2 window. For the thesis, this is important because it means that generators have up until T-2 to decide on their offer strategy, so the generators can respond to market changes that occur prior to this time. This amount of offer flexibility is higher than many other deregulated electricity markets.[21]

2.5.2 Transmission Must Run and Dispatch Down Service

Another change made by the Quick Hits package was the introduction of the Dispatch Down Service ("DDS") market. The DDS market was introduced to compensate for the price depressing effects of Transmission Must Run ("TMR") generation, so the two concepts are closely linked, and are explained here.

TMR is an out-of-market measure used by the system operator to ensure that certain generators supply a specified amount of electricity in the event that this generation is needed to alleviate

[21] See Charles Rivers Associates (2011) 'Electricity Market Data Transparency'.

system reliability concerns.[22] An example of TMR would be that a generator in the Northwest of Alberta is required to supply a certain amount of power to service demand in that area because of systematic transmission congestions. In the absence of the TMR directive, the generator would not be supplying a sufficient amount of energy. Since the TMR generation is procured outside of the market, running TMR reduces the demand for electricity in the market. As a result, the market clearing price is lower than it would have been in the absence of the TMR.

The Quick Hits package introduced the DDS market, a mechanism used to offset the price depressing effect of TMR. Through the DDS market, generators supplying electricity express their willingness to accept a payment to reduce supply. The idea is that reducing the market supply by the amount of TMR will set the market price to the level that it would have been in the absence of TMR.

As an example, Table 2 shows an hourly DDS market on January 6th 2011. In this particular hour 92 MW of TMR was purchased by the Alberta system operator. As a result, market demand was 92 MW lower than it would have been if this generation had cleared through the market. To offset this, the DDS market was used to reduce the supply of electricity into the market by 90 MW (the total of the dispatched MW column). This reduction in supply is replaced by moving back up the supply curve, thus increasing the market price to the level that it would have been without the TMR.

As shown, in this example, NX01 was paid to reduce its supply by 40 MW, SCR1 by 35 MW and BRA by 15 MW. The amount that each generator is paid for DDS is based on its own DDS

[22] The AESO states that TMR is generation that is required to be online and operating at specific levels in particular parts of the Alberta Integrated Electrical System to compensate for insufficient local transmission infrastructure relative to local demand (AESO website).

offer price, which is expressed as discount to the resulting market price. In this example, the energy market cleared at $43.63 so NX01 was paid $(43.63 - 23.99) * 40 = \$786$ to reduce its supply by 40 MW. Payments for DDS are covered by generators supplying electricity in that hour on a pro-rata basis. So a generator supplying 10% of the market's supply would pay for 10% of the hourly DDS payments.

Table 2: An example of the DDS Market (January 6th 2011 HE 12)

Asset Id	DDS Offer Price	Available MW	Dispatched MW
NX01	-$23.99	40	40
SCR1	-$23.5	35	35
BRA	-$23.12	15	15
BIG	-$23.1	10	0
CMH1	-$21.4	15	0
EC01	-$20.01	45	0
MKR1	-$17.1	30	0
BR5	-$5.1	80	0
GN1	$0	25	0
GN2	$0	25	0

An important component of the DDS market is that it is not active when the market price is above a certain reference price. This 'TMR reference price' is set monthly using an AECO-C forward gas price and an assumed 12.5 GJ/MWh heat rate. This yields an estimate of the variable costs for a gas-fired power plant. In January 2011, the relevant gas price was $3.60/GJ, implying that a gas unit with a heat rate of 12.5GJ/MWh would have a variable cost of $45/MWh. So for the duration of January 2011 the TMR reference price was $45.

Before market prices rise above the TMR reference price, all units that are reducing their supply through the DDS market must increase their supply by the DDS dispatch.[23] Continuing with the

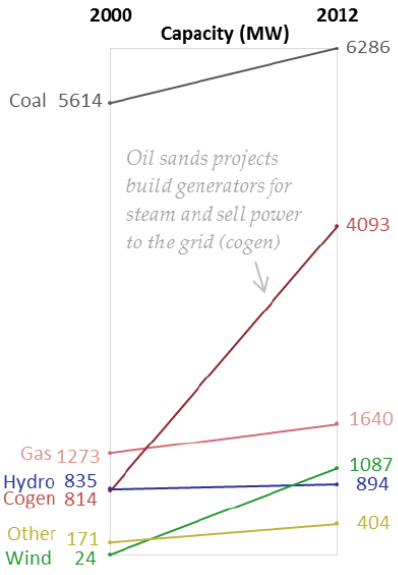
[23] This mechanism prevents DDS being used to increase the market price when the price already above the variable costs of running an (assumed) TMR unit.

above example, before prices could go above $45, the supply of energy would have had to increase by 90 MW, as the units dispatched down would have increased their supply. Also, when market prices fall through the TMR reference price, the DDS units will reduce their supply by the amount of TMR. From a broader markets perspective, this means there will be a large 'shelf' in the market supply function at the TMR reference price when a significant amount of TMR is being used (MSA (2008) "Quick Hits Review: DDS").

2.8 Generation and Ownership Changes (2000 – 2012)

Since its deregulation, Alberta's electricity market has been relatively successful in building additional generation capacity to meet growing demands and to replace retiring capacity (Brattle (2011)). Over 6,800 MW of new capacity has been developed since the market was deregulated in 2000, whilst only 1,400 MW of capacity has been retired. The result has been a net addition of over 5,400 MW (Alberta MSA (2012)).

Figure 3: Cogeneration and Wind have increased their relative capacity since deregulation[24]

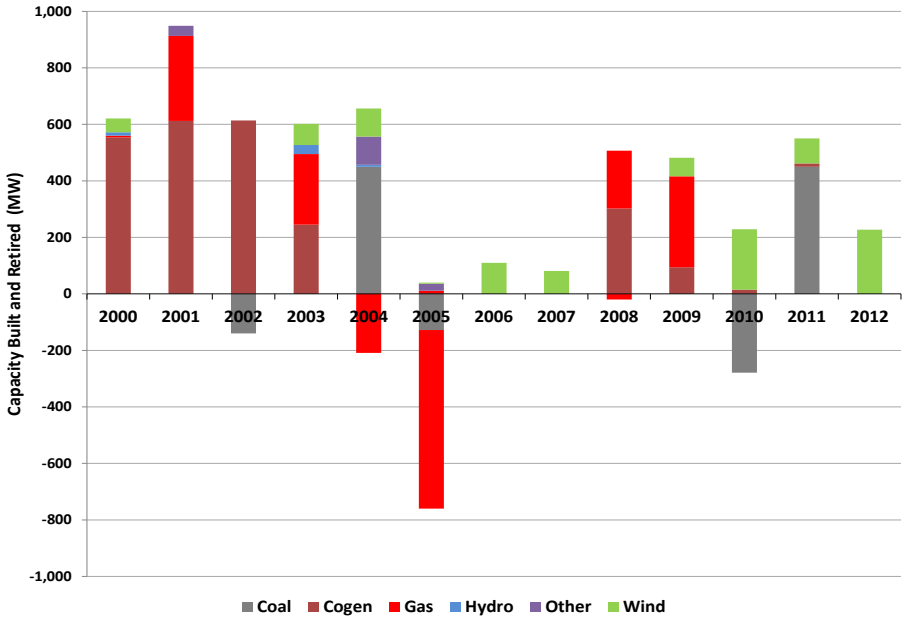


[24] Source: Alberta MSA 'State of the Market Report 2012' (Figure 2.13).

As shown in Figure 3, a significant proportion (some 60%) of the net additions since 2000 have come from developments at cogeneration facilities. These facilities have almost exclusively been built to service the steam and power needs of oil sands operations or related developments. The addition of wind generation, although smaller in absolute terms (1,060 MW), is significant given the low level of wind capacity present in 2000, and the variable nature of wind generation.

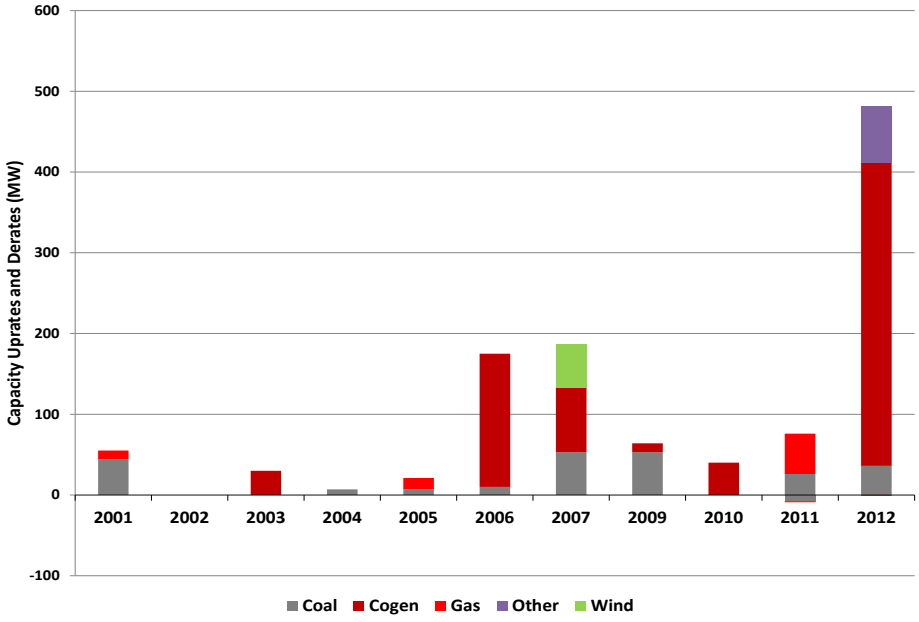
The annual capacity changes by fuel type are illustrated in Figures 4 and 5. Figure 4 shows the generation facilities that have been built and retired in each calendar year since January of 2000. While many generation technologies involve a large amount of capacity being brought online at once, capacity growth has been relatively consistent throughout the period, with only the period 2005 to 2007 seeing relatively little new generation. Uprates, which include additional generators built at existing facilities, have also been an important source of growth; about 20% of the total for net additions (see Figure 5).

Figure 4: Annual Generation Additions and Retirements by fuel type (2000 – Q2 2012)[25]



[25] Source: Alberta MSA 'State of the Market Report 2012' (Figure 2.14).

Figure 5: Uprates have added a total of 1,140 MW since 2000[26]

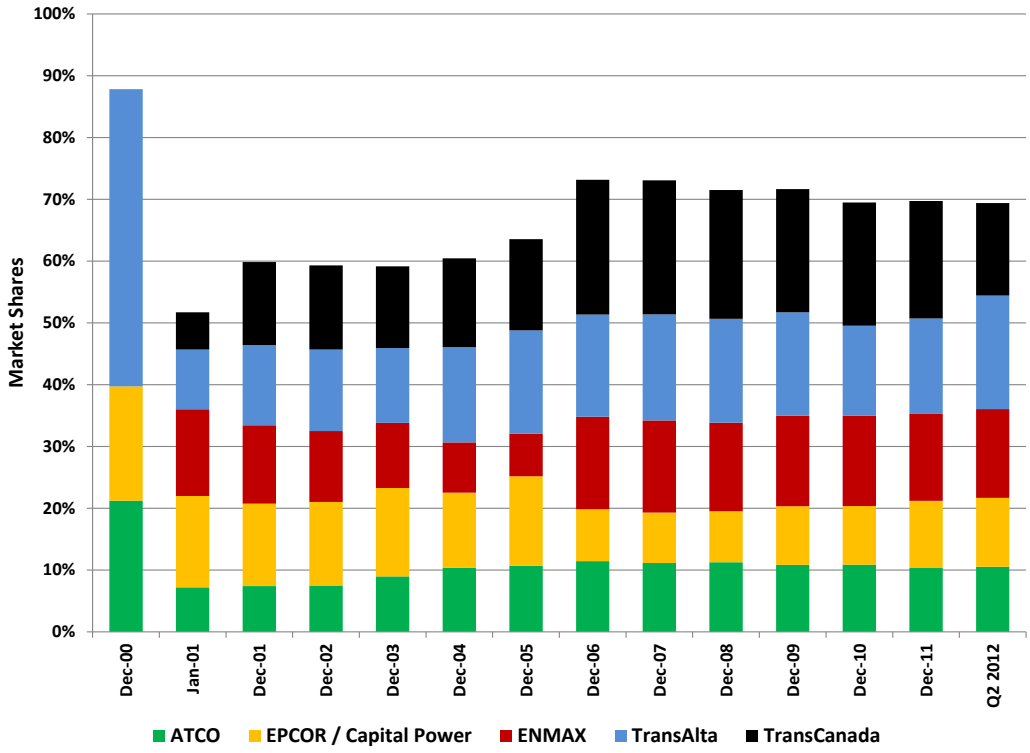


As one would expect, the addition and retirement of various generators has played an important role in determining the dynamics of structural measures such as the concentration of market capacity. However, changes in offer control, most notably on the PPA assets, have also played a significant part in how the Alberta market has developed since its deregulation.

As shown by Figure 6, the impact of the initial PPA auction was to reduce the concentration of offer control over Alberta's market capacity quite significantly. In addition to reducing the offer control of ATCO, EPCOR and TransAlta, the initial PPA auction introduced ENMAX and TransCanada. Together with the three incumbent firms, TransCanada and ENMAX remain the largest firms in the market today. The remainder of this section provides a brief discussion of how these five firms have developed in the Alberta market since 2000.

[26] Source: Alberta MSA 'State of the Market Report 2012' (Figure 2.15).

Figure 6: The Annual market shares of today's largest five firms (2000-2012)[27]



TransCanada

TransCanada's initial presence in the market was relatively small with the firm winning only the auction for the Sundance A PPA. By the end of 2001, the firm's offer control in the market more than doubled as TransCanada and AltaGas formed ASTC power partnership and purchased the Sundance B PPA from ENRON. In addition, TransCanada developed a number of cogeneration facilities from 2001 – 2003, often with large portions of the energy being consumed by on-site hosts.[28] In November 2005, TransCanada was announced as the winning bidder for the Sheerness PPA and took offer control of these units from the Balancing Pool beginning in 2006.

[27] Source: Alberta MSA - 'Measuring Generator Market Power' (Figure 3.1)

[28] See Redwater, Carseland, Bear Creek and MacKay River on TransCanada's website.

ENMAX Energy

Prior to the PPA auction ENMAX was predominantly a wires utility, involved in the regulated development of distribution networks in and around Calgary. In the initial PPA auction, ENMAX purchased the capacity rights to generating assets at Keephills and Wabanum, in total around 1,300 MW of coal-fired capacity. Between 2001 and 2005 ENMAX's market share fell as the overall market grew in size and the Wabamun PPAs came to an end. In 2006 ENMAX increased its market presence significantly as the company obtained offer control of the Calgary Energy Centre (300 MW), and also purchased the Battle River PPA (660 MW) from EPCOR. In 2009 ENMAX added 120 MW of peaking gas-fired capacity to its generation portfolio as the Crossfield facility was brought online. In addition, ENMAX has ~180 MW of wind generation although this does not add to the firm's offer control because wind generation is not dispatchable (i.e. cannot be offered at a price).

Capital Power (previously EPCOR)

EPCOR was the only incumbent utility to become a PPA Buyer as the company purchased the Battle River and Sundance C PPAs in the initial auction. In terms of its assets built under regulation, EPCOR's Cloverbar and Genesee units were not sold in the initial PPA auction and were initially managed by the Balancing Pool. The Cloverbar units were later sold in multiple auctions before being retired in 2004 – 2005; the Balancing Pool has retained offer control of the Gensee units to this day. EPCOR's Rossdale units were sold to Engage Energy in the initial PPA auction although these units returned to EPCOR in 2003 before being retired the following year. In 2005 EPCOR and TransAlta completed the development of Genesee #3; an asset built by means of a joint venture, with each company controlling half of the unit's capacity. In 2006,

EPCOR reduced its market shares as the company sold the Battle River PPA to ENMAX. In 2008/09 EPCOR brought three gas-fired peaking plants online for a combined capacity of 250 MW; these units operate on the same site as the old Cloverbar gas units.

EPCOR separated its wires business from its generation portfolio in June 2009 when EPCOR Utilities divested its generation assets to Capital Power Corporation and kept its interests in the electricity market focused on transmission and distribution developments. However, there was effectively a transition period until July of 2011 in which Capital Power was responsible for supplying EPCOR's Regulated Retail Obligations (RRO). Consequently, Capital Power was effectively a vertically integrated firm to some extent until July of 2011 (Alberta MSA (Q3 2011)). In 2011 Capital Power and TransAlta commissioned another joint-venture coal unit, with each firm gaining 225 MW of the Keephills #3 unit. The most recent addition to Capital Power's portfolio was the addition of 150 MW of wind generation at Halkirk. This facility is sold into the Alberta market and collects Renewable Energy Credits (RECs) from Pacific Gas and Electric in California.

TransAlta

Prior to the initial PPA, TransAlta was the largest generator in Alberta and after the initial auction TransAlta was the PPA Owner for over 3,600 MW of thermal capacity. In addition to its thermal generation TransAlta had developed 800 MW of hydro capacity under the regulation regime. However, due to the complexities involved in operation hydro facilities the Independent Assessment Team ("IAT") felt that it was imprudent to emplace the typical owner-buyer relationship on these units. As a result, TransAlta continues to have offer control over these facilities and the Hydro PPA is a series of financial obligations based on historical water flows

and realized pool prices. TransAlta has continued to develop capacity in Alberta since 2000 with the major developments being Genesee #3, Keephills #3 and the Suncor cogeneration facility ('Poplar Creek'). TransAlta has also continued to uprate the assets that were built under deregulation, adding over 200 MW of capacity at facilities on which the company is a PPA Owner. In addition, TransAlta has the largest wind portfolio in Alberta presently owning ~450 MW of wind capacity in the province.

ATCO

Since deregulation ATCO has been relatively quiet in terms of developing "merchant" generation capacity in Alberta. Since the market's deregulation, ATCO has commissioned a number of cogeneration facilities; Rainbow Lake #4 and #5 (97 MW), Joffre (474 MW), Muskeg River (202 MW) and the Scotford Upgrader (195 MW). These cogeneration facilities have all been developed alongside various on-site loads, with the on-site loads purchasing a significant portion of the power and steam through long-term contracts. In addition, ATCO has added 100 MW of peaking gas capacity at its Valley View site and has developed a 32 MW run-of-the-river hydro facility on the Oldman River.

Cogeneration and Energy Developments

As shown by Figure 3, a large amount of the generation developments in Alberta since the market's deregulation have been cogeneration units. Unsurprisingly, the majority of these developments have been made by large energy companies involved in the extraction of oil from the Alberta oilsands, and these developments form a significant portion of the capacity developed by 'Other' firms. It is clear that the majority of these investments have been made based on the steam and electricity demands for the primary industrial process at these sites. To

this extent, these developments have arguably been made ‘outside’ of the deregulated Alberta electricity market. However, these cogeneration facilities play an important role in the nature of competition in the Alberta market place. For rival generators, these facilities represent an important source of competition because they directly supply a substantial portion of Alberta’s industrial power demands, and often supply meaningful amounts of excess power to the broader market.

Chapter 3: Alberta's Electricity Market Structure and Fundamentals

3.1 Alberta's 'Energy-Only' Market Design

The overall market design is crucial to understanding the space within which generators compete in the Alberta power market. Alberta's 'energy-only' market design is unique in comparison with many other deregulated electricity markets. The term energy-only refers to the fact that generators offering into the Alberta energy market only receive payments for the electrical energy delivered onto the grid.[29] This design is in contrast with many other electricity market designs because generators in Alberta do not receive payments for capacity (i.e. providing the potential to generate electricity). Under capacity market frameworks, generators are paid for both the energy they produce as well as the capacity they have available. These capacity payments provide generators with a fairly certain stream of revenues going forward, so firms can be relatively confident that the fixed capital costs of their investment will be recovered.[30]

In Alberta's energy only market, generators must recover their costs through the revenues earned from providing electricity. Unlike in capacity markets, the Alberta energy-only market design places all of the risks inherent in developing new generation capacity onto the market, and the private sector is left to decide on the timing of new generation and plant retirements. If the future demand for electricity is forecast to be high relative to the future supply of electricity, the expected profitability of building new generation capacity will be higher. Under Alberta's market design, investment decisions are principally driven by these fundamentals. This hands-

[29] Generators and load participants can receive payments for providing Ancillary Services (or Operating Reserves) although this revenue is a small portion of the wholesale sector.

[30] For a comprehensive discussion of various electricity market designs see Brattle (2009).

off market design is in contrast with most other electricity markets where the amount of capacity required is determined by the ISO's centrally-administered resource adequacy metrics or by other planning mechanisms.

Apart from a price cap ($1,000) and a price floor ($0), outcomes in the real-time Alberta Energy Market are determined solely by the forces of competition. The Alberta electricity market is not a cost-based market and generators are under no obligation to offer their energy at some proxy of variable cost. Thus, unlike most deregulated electricity markets, participants are free to engage in unilateral strategies in an attempt to move the pool price, as long as they do not impede competition or physically withhold generation from the market (Alberta MSA "OBEGs" (2011)).

In this way, the design of Alberta's electricity market is like many other deregulated markets and implicitly relies on the generation sector being 'workably competitive'. To be workably competitive requires that prices are sufficient to drive prudent new investment if it is required. In this sense, the ability of generators to take advantage of profitable market situations is arguably essential for the future development of generation capacity in the Alberta market, as these profitable situations provide the means to recover the fixed costs that are associated with developing generating capacity. However, at the same time, the long-run sustainability of the market requires that market outcomes are not exclusively determined by the actions of a few large generating firms. Consequently, the unique design of Alberta's electricity market means that measuring and monitoring the extent of generator market power is a subject of great importance to the industry.

3.2 The Operation of Alberta's Wholesale Electricity Market

The Alberta Energy market operates in real-time based on the prevailing supply and demand in the province. For every hour, suppliers offer blocks of energy into the market at the price for which they are willing to sell their generation. Conversely, loads may bid into the market to reflect the price they are willing to pay for electricity. Note that while generators have an obligation to offer all available energy into the market, loads have no such obligation to bid. Loads which are not bid into the market act as a price taker and simply pay the resulting pool price. In practical terms, loads have not bid into the energy market for several years.

Imports, exports and wind generation are all treated as price-takers according to the current market rules. Imports into Alberta must offer their energy into the market at $0 meaning that they obtain any positive pool price for supplying energy. Similarly, exports from Alberta pay the resulting pool price and cannot bid into the market. Exports are included in the Alberta market supply curve (the Energy Market Merit Order (EMMO)) at $999.99 since in the event of a supply shortfall, the AESO have the ability to retain these MW within Alberta. At present, wind generation cannot be offered into the energy market since its fuel source is variable. Instead, wind capacity supplies all generated energy and its supply is only curtailed in the event of a supply surplus.[31]

For every hour each generating asset in Alberta can submit up to 7 price-quantity offers into the energy market which reflect the unit's willingness to supply electricity. Generators can offer their energy at any price between $0 and $999.99 and must offer all available capacity. Table 2 below provides an example of a generator's offer curve which utilizes all seven price-quantity

[31] Supply surplus events occur when demand falls below the generation offered at $0.

blocks.[32] The initial offer block shows that, at this particular time, the coal unit was willing to supply 135 MWh for $0. That is, the unit is willing to supply 135 MWh regardless of the prevailing market price. $0 offers are an important feature of the Alberta energy market and are discussed further in the 'Market Supply' section of this chapter.[33] The second offer block shows that at a price of $13.15 the generator would be willing to generate a total of 200 MWh, providing an additional 65 MWh on the initial block. Likewise, the third offer shows that the unit would be willing to supply 250 MWh, an additional 50 MWh, if it received a price of $18.24 or greater.

Table 3: The offer curve submitted for Sheerness #1 (August 5th 2012 from 6pm to 7pm)

Date	HE	Asset Id	Block #	Price	From	To	Size	Available
05/08/2012	19	SH1	6	$56.6	365	390	25	25
05/08/2012	19	SH1	5	$46.51	330	365	35	35
05/08/2012	19	SH1	4	$36.42	312	330	18	18
05/08/2012	19	SH1	3	$28.33	250	312	62	62
05/08/2012	19	SH1	2	$18.24	200	250	50	50
05/08/2012	19	SH1	1	$13.15	135	200	65	65
05/08/2012	19	SH1	0	$0	0	135	135	135

For every hour the AESO construct the Energy Market Merit Order (EMMO) by aggregating the offer curves submitted by every generator in the province. The EMMO is constructed in order of ascending offer price and it is the job of the AESO's System Controller to dispatch energy based on the merit order. Lower priced energy is dispatched first and the System Controller moves up the merit order to the point where supply is sufficient to meet prevailing market demand.

[32] In practice few generating units use all of the seven blocks that they are allocated.

[33] In this instance the offer reflects an operational constraint. To remain operational, the Sheerness unit must generate at least 135 MW of energy or be dispatched off entirely. Once off, coal-fired generators are slow and expensive to start-up. To avoid this issue, traders frequently offer the Minimum Stable Generation (MSG) at $0.

The prevailing market price (the System Marginal Price (SMP)) is set by the offer price of the marginal unit (i.e. the highest priced block that is dispatched). The SMP can change from one minute to the next according to changes in supply and demand. The hourly Pool Price is calculated at the end of each hour as the time-weighted average of the SMPs. The Pool Price is the price that suppliers receive for their generation and is the price that loads must pay for the energy consumed.

3.3 The Supply and Demand for Electricity in Alberta

3.3.1 Market Demand Fundamentals

The ability or willingness of consumers to substitute away from consuming electricity in the event of price rises has an important impact upon the market power of generators. Microeconomic theory shows that the elasticity of market demand is important for understanding market power. As the market demand function becomes increasingly inelastic, the unilateral market power of suppliers increases. Intuitively, because suppliers will face a lower fall in demand as prices rise, the ability of suppliers to profitably raise the market price by withholding output increases.

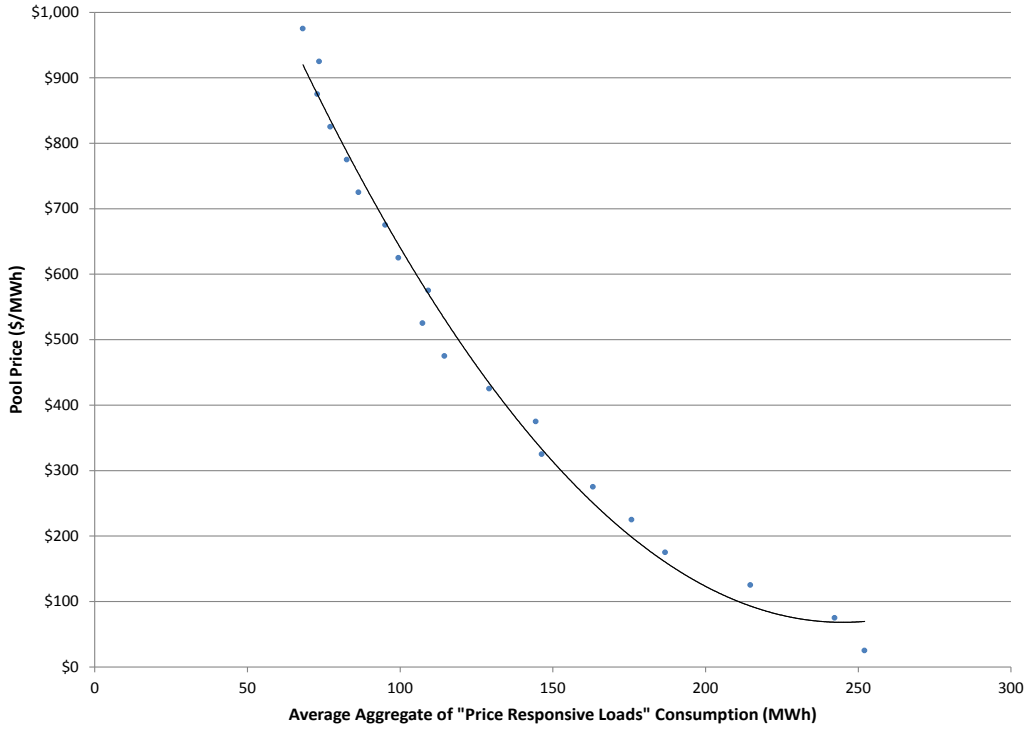
The demand for electricity is almost perfectly inelastic in the short-run as the majority of consumers do not respond to changes in the real-time price. The reasons for this are two-fold. Firstly, most consumers are not exposed to the real-time price of electricity but instead pay for their power through a fixed-price contract via an electrical retailer. As a result, the final consumers of electricity rarely have the incentives to reduce their power demands as real-time prices spike. Secondly, electricity is a commodity with almost no substitutes so the price at which it becomes economical for consumers to reduce demand is exceedingly high; authors such

as Stoft estimate the Value of Lost Load ("VOLL") to be in the region of $10,000 – $20,000 / MWh.

So-called 'price responsive loads' are therefore limited to a small number of industrial consumers that monitor prices in real-time and curtail demand when prices spike above a certain level. For these firms, electricity is a major component of costs, and their production processes are flexible enough to reduce power consumption without undue consternation (the printing press is a good example). Analysis by the AESO in 2009 suggests that these are normally around 250 MW of price responsive loads, which tend to be particularly sensitive when prices go upwards of $100 (AESO (2009b) "Currently Existing Demand Response").

Therefore, it is not surprising that the demand for electricity in Alberta is very inelastic to the pool price. In the wholesale market, there is typically no more than 250 MW of price-responsive load at any given time. This price-responsive load is a small fraction of the Alberta market, where total demand rises above 10,000 MW during peak times. Given that the market demand for electricity in Alberta is very inelastic, the response of demand to price changes will provide little constraint for the ability of generators to exercise market power.

Figure 7: The average demand of 'Price Responsive Loads' at $50 price intervals



The market power of generators also varies as the prevailing level of market demand changes. In electricity markets, non-storability and capacity constraints mean that variations in market demand can have a significant effect upon the supply-response faced by generators. As discussed in 1.5.1, electricity is a distinct commodity because it cannot economically be stored, and its production is subject to strict capacity constraints in the short-run. Therefore during times of high demand, rival firms are often meaningfully constrained because generation cannot be increased beyond physical capacity limits, and electricity cannot be generated beforehand and stored in anticipation of the market conditions. Consequently, the supply response can be significantly limited at times of peak demand and the price rise a firm can obtain by withholding a relatively small amount of generation may be substantial during these periods. On the other hand, when the demand for electricity is low there is often a significant amount of excess

capacity available to the market and the ability of firms to exercise market power at these times will be limited.

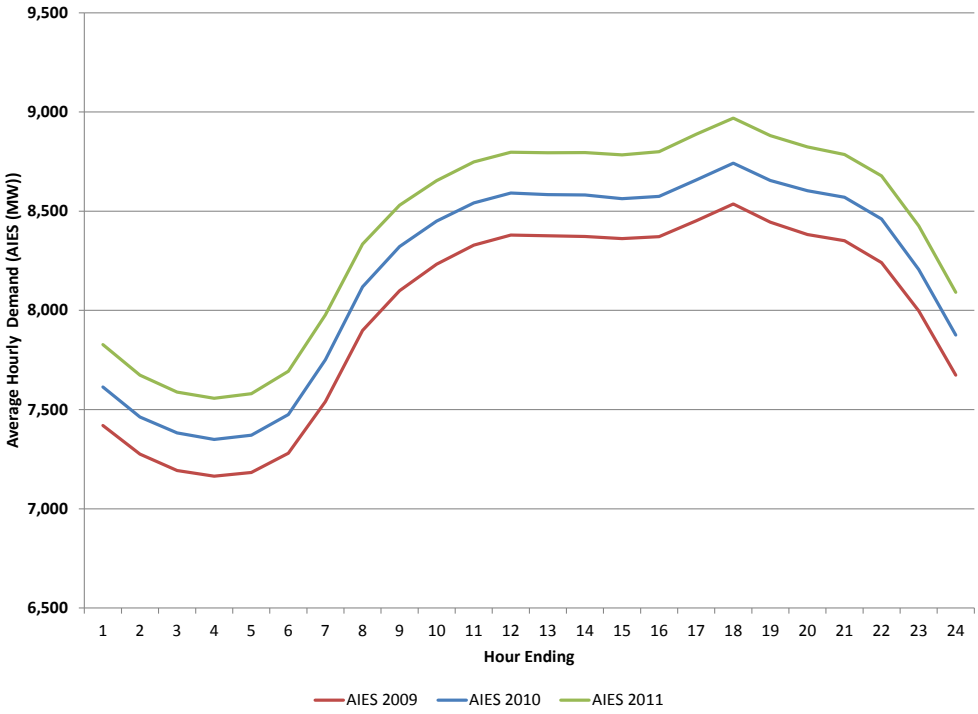
Demand for electricity in Alberta is driven predominantly by the demands of industrial sites and commercial operations (see Table 4). As a result of this, the baseload demands for electricity in Alberta are high relative to the peaks in electricity demand. In 2011 for example, the average hourly Alberta Interconnected Electrical System ("AIES") load was 8,400 MW; this average is over 80% of the year's peak in demand, set at 10,230 MW.

Table 4: Alberta Internal Load by sector in 2010 (Source AESO Long-Term Transmission Plan 2012).

Sector	Annual Energy	Percent
Industrial (without Oilsands)	31,525 GWh	44%
Commercial	13,748 GWh	19%
Oilsands	11,134 GWh	16%
Residential	9,071 GWh	13%
Losses	4,537 GWh	6%
Farm	1,708 GWh	2%
TOTAL	**71,723 GWh**	**100%**

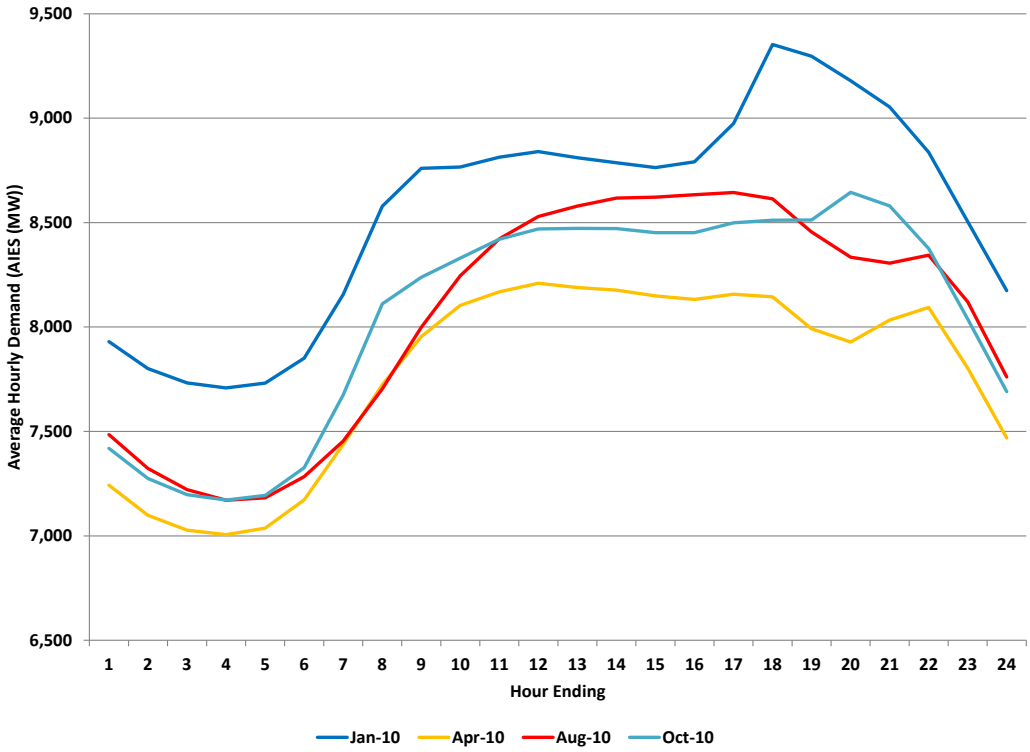
Because Alberta's industrial demand is relatively consistent, variations in total market demand tend to follow variations in residential and commercial demands (see Figure 8). As shown, the intra-day variations in the demand for electricity tend to follow the lifestyle of the typical Alberta population. Demand increases in the morning hours as people are waking up, and in the early evening as consumers arrive home. Demand for electricity ramps down later in the evening, bottoming out at around 4am.

Figure 8: The Average hourly Load Shape in Alberta



The strong seasonal weather in Alberta means that this daily cycle does vary considerably depending upon the time of year and the prevailing weather conditions. To see this, Figure 9 shows the average hourly demand for January, April, August and October of 2010. In January there is a significant increase in demand from 17:00 to 19:00 (HE 16 to HE 19) as residents return home and start cooking at the same time as the streetlights come on. In contrast, the summer month of August shows a fall in demand around this time as the evening cools down and consumers no longer require air conditioning.

Figure 9: The hourly Load profile in Alberta varies across seasons

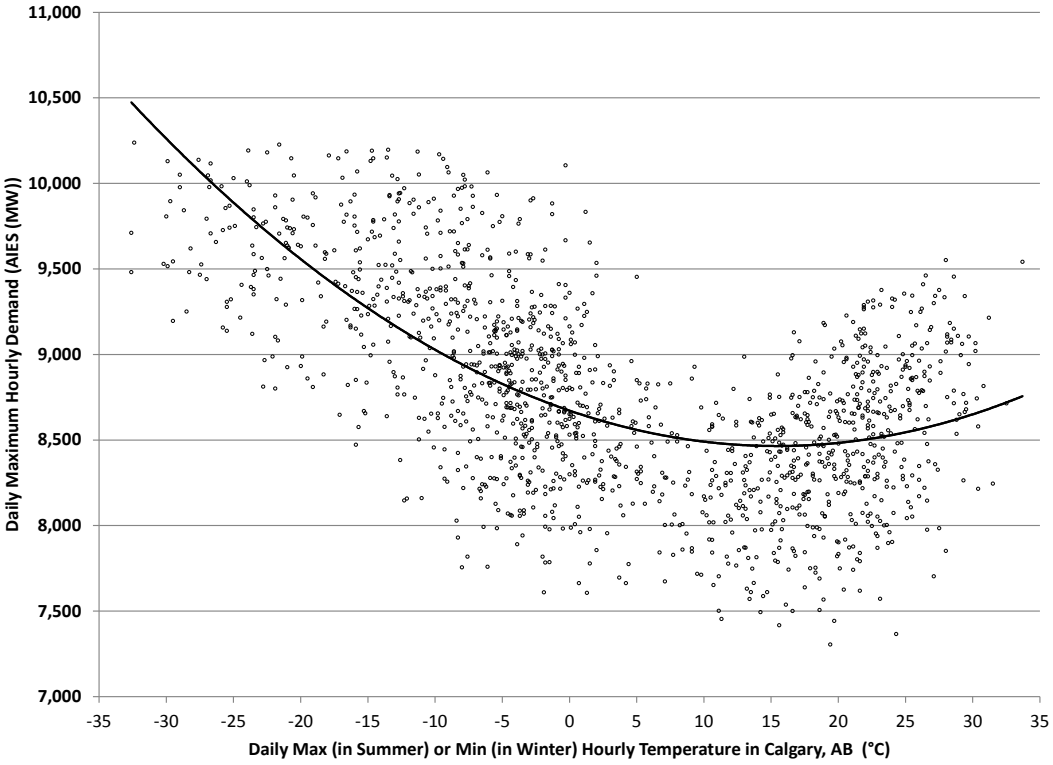


In addition, Figure 9 indicates that market demand tends to be highest in the winter season when Alberta's temperatures frequently drop below -15 °C (January 2010 was particularly cold). In comparison with the summer load shape, the winter demand profile is shown to be notably higher during the early morning hours, while the spread between the two is less notable in the early afternoon.

Unsurprisingly in Alberta, temperatures play an important role in determining peaks in electricity demand. As shown by the scatter plot in Figure 10, peak demand for electricity tends to occur on abnormally cold days, and to a lesser extent, when the prevailing temperatures are hot. In terms of the thesis, it is important to note that while demand peaks in summer are less than the peaks observed in winter, the supply of generation capacity in Alberta is often depressed in the event of consistently hot temperatures because thermal capacity does not cope well with hot weather. In

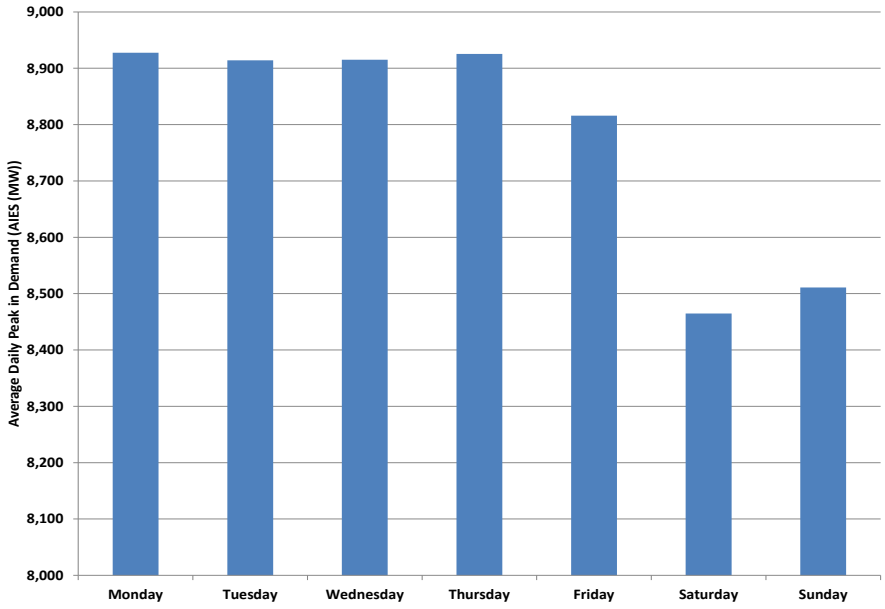
contrast, Alberta's thermal capacity tends to perform optimally when the weather is cold. Consequently, the supply-demand fundamentals can be very tight on peak summer days even though market demand may be low in comparison with the winter peaks.

Figure 10: Prevailing weather conditions play an important role in the demand for electricity



The demand for electricity in Alberta also varies predictably across the days of the week, with demand being less on Saturday, Sunday and on statutory holidays than on working days. The extent of this variation is illustrated in Figure 11. As shown, the average peak demand on Saturday and Sunday is approximately 400 MW less than the average weekday peak. As well, peak demand is shown to be around 100 MW less on a typical Friday in comparison with other working days; demand for power is generally relatively low on Friday afternoons.

Figure 11: Demand for electricity is higher during the week



Although these short-run variations in market demand are fairly understandable, forecasting demand in the long-run is not straightforward as it typically requires forecasting Alberta's future macroeconomic performance and the growth rate of Alberta's oilsand industry. Each year the AESO publishes a future demand and energy outlook, detailing load forecasts for the next 20 years, along with the methodology underlying these forecasts.

3.3.2 Market Supply Fundamentals

In Alberta the dominant types of generation, as classified by fuel source, are coal and natural gas. In 2011, coal accounted for 67% and natural gas for almost 20% of the total annual generation. In terms of capacity, over 80% of the Province's generation capacity is provided by coal and gas-fired assets (Table 5). On top of this thermal capacity, wind, hydro and biomass generation are also present in Alberta.

Table 5: Alberta Capacity by Fuel (Source AESO CSD page Aug 2013)

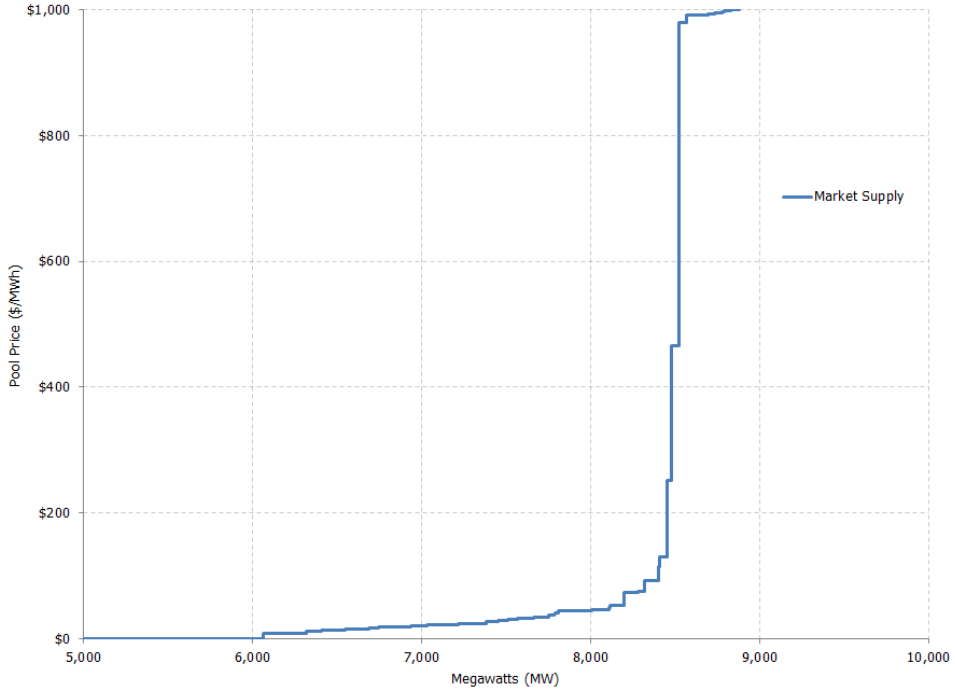
Fuel Source	Capacity (MW)	% of Total
Coal	6,271	43%
Gas	5,880	40%
Hydro	894	6%
Other (Biomass)	423	3%
Wind	1,088	7%
TOTAL	**14,556**	**100%**

Figure 12 shows an example of the energy market supply function. As shown, the Figure illustrates over 6,000 MW of generation being offered at $0. More often than not, zero dollar offers are a means by which generators can ensure their units will remain in-merit and not be dispatched off (Alberta MSA (2003) “Zero Dollar Offers”). Moving up the supply function, approximately 1,800 MW of generation is offered between $0 and $130. This yields the gentle sloping section illustrated, highlighting that the market supply is relatively elastic in this region. For the majority of hours, the market clears in this region of the supply curve.

Above this competitive section, the supply curve becomes relatively steep until the price reaches the upper $900s. In this example, the supply function illustrates that only an additional 120 MW

was offered into the market between $130 and $980. In this region the market price is very sensitive to changes in the market fundamentals because the supply function is inelastic. Between $980 and the price cap at $999.99 the supply function is fairly flat, as approximately 400 MW of generation was offered into the market above $980 – many of these generators offered in this range are participating in the Ancillary Services markets.

Figure 12: A graphical example of the Energy Market Merit Order in January 2011



The generic shape of the supply function depicted in Figure 12 is fairly typical of the Alberta Energy Market supply function. In particular, it is common to see a significant amount of generation offered at $0 and to see the supply function being relatively elastic below $100. Above this price range the supply function is normally very steep until the upper $900s. In this steep section of the curve, the market supply will only respond to substantial changes in price.

Although this generic shape of the supply function above is insightful, it is important to highlight that the shape and position of the market supply function can change substantially from one hour

to the next according to unit outages and derates, variable flows on the interties, as well as variations in wind generation[34]. In addition, the market supply function will vary as generators alter their offer strategies in order to adjust for cost / operational changes, or to take advantage of profitable market opportunities. While some of these variations (scheduled outages, seasonal derates, import / export flows) are relatively easy to forecast at T-2, other variations in market supply are often not easy to understand 2-3 hours ahead of real-time (forced outages and wind supply are the primary examples).

Alberta's aggregate market supply function will essentially depend on the operational and physical characteristics of the generation assets that participate in the energy market. The remainder of this section details the characteristics of each fuel type to inform the discussion of market supply further.

Coal-fired Generation

Almost 45% of Alberta's capacity is coal-fired generation. Coal generation is typically characterised as 'baseload'[35] generation because these units are designed to operate at a consistently high level around the clock. Coal plants have high fixed and start-up costs but their variable costs are low. The operational performance of coal-fired generators is generally maximized by having the units generate at a constant level since coal plants are costly and relatively slow to ramp up and down. Additionally, coal units are characterised by a Minimum Stable Generation (MSG) and the plants cannot operate safely at lower levels for extended

[34] Strictly speaking, wind generation is not included in the Energy Market supply function since it is not offered at a price. From a practical perspective however, the impact of wind generation is to vary demand in the energy market; higher wind will reduce the amount of electricity generation needed from the Energy Market, thus shifting the intersection of demand and supply to the left and lowering prices.

[35] Baseload plants are generating facilities used to meet continuous energy demands. These plants produce energy at a constant rate which does not tend to vary with changes in market demand.

periods, so the plants must either generate greater than this amount of power or not generate at all. The available capacity of coal generation can vary seasonally, particularly if cooling ponds are part of the generation process. During hot summer days the effectiveness of the cooling pond is decreased as the cooling water temperature rises, decreasing the efficiency of the plant and preventing the plant from operating at full capacity.

Because frequent starts and stops are quite costly, the MSG of coal plants is often offered in at $0 in order to prevent the plants from being dispatched off. From an operational stand point, the ramping up and down of coal plants is quite costly and will tend to increase wear on the plant. However, many of the coal plants within Alberta are operated under Power Purchase Arrangements and it is not the concern of the PPA Buyer to maximize the operational lifespan of the generating facility. This, in combination with the low price of natural gas, means that coal units are often at the margin in Alberta. For the majority of hours, the capacity of coal plants above the MSG is offered in the range of $10-$30 reflecting the variable costs of generation, although higher offer prices are observed in hours when profitable opportunities arise.

Gas-fired Generation: Co-generation and Peaking

As well as an abundance of coal, the province of Alberta is also rich in natural gas resources. Since the production of oil from Alberta's oilsands requires large amounts of steam and electricity, it is not surprising that over 3,000 MW of co-generation capacity have been added to the market since its deregulation. These co-generation facilities allow for economies of scope (i.e. lower production costs) to be achieved as steam and electricity are produced simultaneously from the burning of natural gas. The primary operations (oil production from SAG-D for instance) at these co-generation plants often require long, uninterrupted periods of substantial

steam or heat generation. Electricity is either a critical input to, or bi-product of, this primary on-site operation. As a result, these assets are frequently price-takers since the decision to generate is often independent of prevailing electricity prices. In other words, the large presence of co-generation capacity offered at $0 reflects electricity which is produced and consumed on-site, as well as excess electricity that is supplied onto the grid as a result of the steam needed for the on-site industrial process. In addition to offers at $0 offers, some co-generation units do offer energy into the merit order at a price, illustrating that these plants have the option of generating further electricity in response to market prices.

Conventional gas-fired generation is typically characterized as peaking generation as these units tend to be dispatched during peak hours when demand is high. However, the low prices of natural gas and the improvements in combined cycle technology mean that this characterization is becoming less apparent. In comparison with coal-fired assets, gas generation is generally more flexible in its ability to ramp generation up and down quickly, and the fixed-costs of peaking gas plants are relatively low. The variable cost of gas-fired generation depends upon the prevailing price of natural gas and the heat rate of the plant. A heat rate of 10 GJ/MWh and a gas price of $8 /GJ imply a variable cost of approximately $80 /MWh, whereas a heat rate of 8 GJ/MWh and a gas price of $2/GJ imply a variable cost in the region of $16 /MWh. This latter calculation illustrates why the variable-cost distinction between coal and gas-fired generation has become less obvious recently.

The efficiency and capacity of all gas-fired generation in Alberta varies seasonally depending upon the ambient air temperatures. Gas-fired generation will become increasingly efficient (i.e. will have a lower heat rate) as the air temperature decreases. In contrast the units will tend to be

less efficient on hot summer days, when the capacity of the units is also likely to be derated because of the heat.

Hydroelectric Generation

Alberta has over 800 MW of hydro generation capacity. The majority of this capacity is supplied by two large assets on the North Saskatchewan River system (Brazeau and Bighorn) and a number of smaller hydro facilities located on the Bow River System, which are all offered into the market under one asset (Bow River). Hydro generation is seasonal as the amount of electricity that can be generated depends upon the supply of water in the reservoirs behind the dams. The water supply to hydro assets in Alberta is highly dependent upon climatic conditions including the level of snowmelt and rainfall. Therefore, hydro generation tends to be greatest in the spring and lower in the winter and summer months.

All hydro assets are constrained by the seasonality of water supply and by storage limitations. As a result, the notion of capacity for hydro generators is very different from thermal generators. Because of limited water supplies, hydro assets cannot maintain generation levels at the units' capacity for extended periods of time. As with thermal generation, hydro units often offer a portion of their generation into the energy market at $0. At the larger hydro facilities this is normally because of environmental restrictions or storage limitations (when the dam is full the unit must either generate electricity or spill the water).[36] In addition, some of the province's smaller hydro facilities are 'run-of-the-river' units with little to no storage capacity. These units

[36] Even if it's economic, the spilling of large volumes of water is obviously something that can face notable environmental and/or political constraints.

can either run the river through the turbines at a variable cost of close to $0, or allow the river to spill through the dam.

Hydroelectric units are expensive to develop but, once built, their variable costs of production are very low. However the marginal costs of using damned water to generate electricity are not determined by production costs but by the opportunity costs associated with using the stored water now. Without using a priced commodity to generate power, operators of hydro plants must decide when to produce and sell their power. These decisions are made primarily on the basis of what their opportunity costs would be in selling the power at a different time or place (Williams (2002)). As a result, hydro assets often offer their potential generation into the market at very high prices when they are expecting future prices to be more profitable. Hydro assets then are typically characterised as peaking generation and tend to generate their full capacity only when prices are high. In addition, hydro assets sell a fair amount of operating reserves into the Ancillary Services market as these sales allow the assets to generate revenues without using up the valuable water.

Wind Generation

At present, there are over 1,000 MW of wind generation capacity in Alberta. Wind generation was almost non-existent in the Alberta market of 1998 and the effect of wind generation on the Alberta market has grown notably over recent years. Furthermore, this growth rate may rise considerably in the coming years as a number of wind developments are currently being built, and a significant number of projects have received regulatory approval (see AESO Long Term Adequacy metrics).

The operation of a wind generator in Alberta is straightforward; when the wind blows the unit generates electricity. All of this electricity is supplied onto the Alberta grid, unless the market is in supply surplus or if transmission constraints are a limiting factor. The majority of wind generation is located in the South of the province around the Pincher Creek area, although a few assets have recently been developed in the central and northern regions. Wind capacity is fairly expensive to develop, costing in the region of $2.5 million per MW of capacity, but the variable and maintenance costs are low in comparison with other generating types.

Wind is a variable fuel source which can change the market supply fundamentals in Alberta very quickly. On average the capacity factor of wind in Alberta is around 30%. However, wind generation tends to be almost non-existent on the peak days of the year when the Alberta temperatures are in the plus or minus 25s. In addition to this, the supplies of wind generation from each asset in Alberta are highly correlated with one another. As a result, total wind generation can vary significantly in a short space of time, and changes upwards of 600 MWh in 20 minutes are not uncommon.

Understanding the variations in wind supply has becoming increasingly important for generators in Alberta as the presence of wind power has increased substantially in recent years. On days of peak-demand when the presence of wind generation is low, generators will tend to have an increased amount market power. In contrast, even if demand is high, when wind supply is elevated generators will tend to have less market power as the demand curve will intersect further down the supply function where the market supply function tends to be more elastic.

Interties (Imports and Exports of Electricity)

Interties play an important role in the Alberta market. For in-province generators, the interties represent both a source of competition (via imports) and an opportunity to access other markets (via exports). At present, imports and exports must act as price takers in the Alberta market. Imports must be offered into the market at $0 and will receive the prevailing market price for their energy. Firm's wishing to export from Alberta will pay the Alberta market price to flow energy into other jurisdictions. These rules were implemented in November of 2000 in response to the California energy crisis, and the resulting price spikes in Alberta. The net flow of electricity on the interties frequently has an important impact on the prevailing market price in Alberta. By increasing the market supply at $0, the flow of imports into the province will tend to decrease the energy market price. In contrast, the flow of exports from Alberta increases the demand for generation within the province, increasing the Alberta pool price.

In comparison with other electricity markets, Alberta's interconnections with its neighbours are relatively small in proportion to overall load. Typically, the two tie-lines into Alberta from neighboring jurisdictions have combined Available Transmission Capacity ("ATC") of around 650-700 MW. Alberta has two interconnections; one to British Columbia and one to Saskatchewan. A third interconnection to Montana is currently being added, although it is not expected that the Montana tie will increase the aggregate transmission capacity of Alberta's interties due to its interactions with the BC intertie. Table 6 summarizes the distribution of the hourly transmission capacity that has been available on Alberta's two interties in recent years.

Table 6: The Available Capacity on Alberta's Interties (Jan 2010 – Sep 2012)

	Available Transmission Capability (MW)			
Percentile	**BC Import**	**BC Export**	**Sas. Import**	**Sas. Export**
5th	400	0	0	0
25th	500	0	153	75
50th (Median)	500	439	153	153
75th	575	735	153	153
95th	600	735	153	153

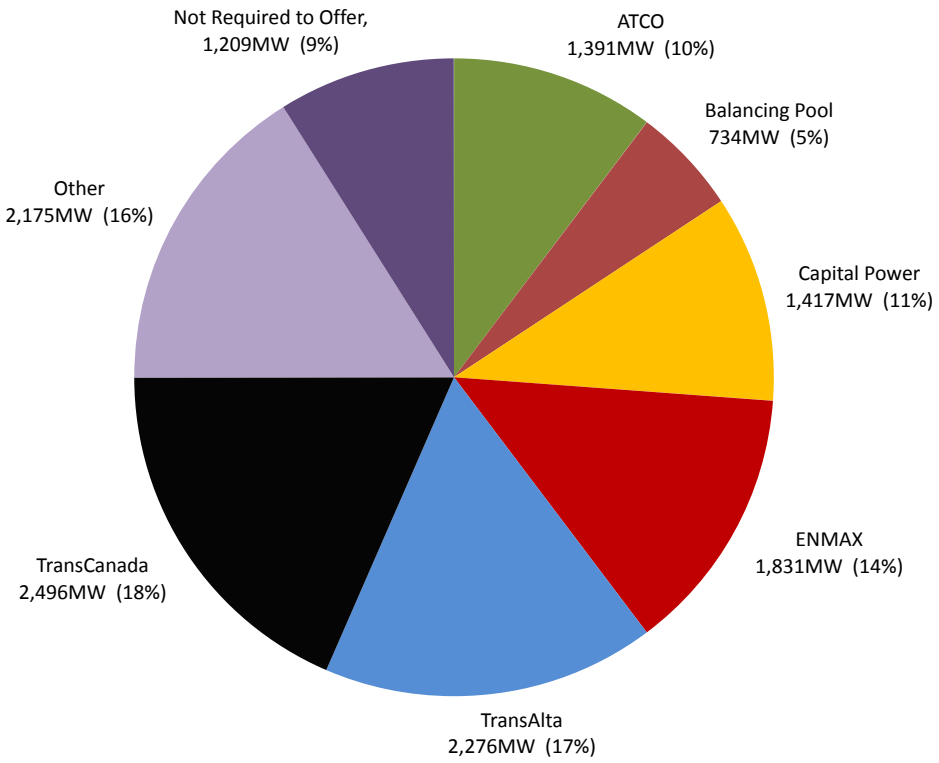
Although there are no markets in British Columbia and Saskatchewan, both can serve as conduits to access electricity markets elsewhere. Through British Columbia market participants have access to electricity in Mid-C (an important and liquid bilateral market in Mid-Columbia) and other potential markets such as California. Through Saskatchewan there is the potential access to the market administered by the Midwest ISO, however, transmission constraints elsewhere often limit the opportunities for energy to flow between Alberta and markets to the east of Saskatchewan.

3.4 Control over Generation Capacity

The Alberta wholesale electricity market is relatively concentrated. According to recent Offer Control estimates, the largest 5 firms in the market control 70% of total market capacity (see Figure 13). However, the offer control of generation capacity is not particularly straightforward in Alberta. As shown in Figure 14 on following page there are a large number of units in Alberta with ownership inter-linkages. Consequently, the actual (i.e. effective) offer control that firms

have at many of these assets will depend upon the nature of the contractual arrangements, and it is often unclear which party has offer control over a particular offer-block.[37]

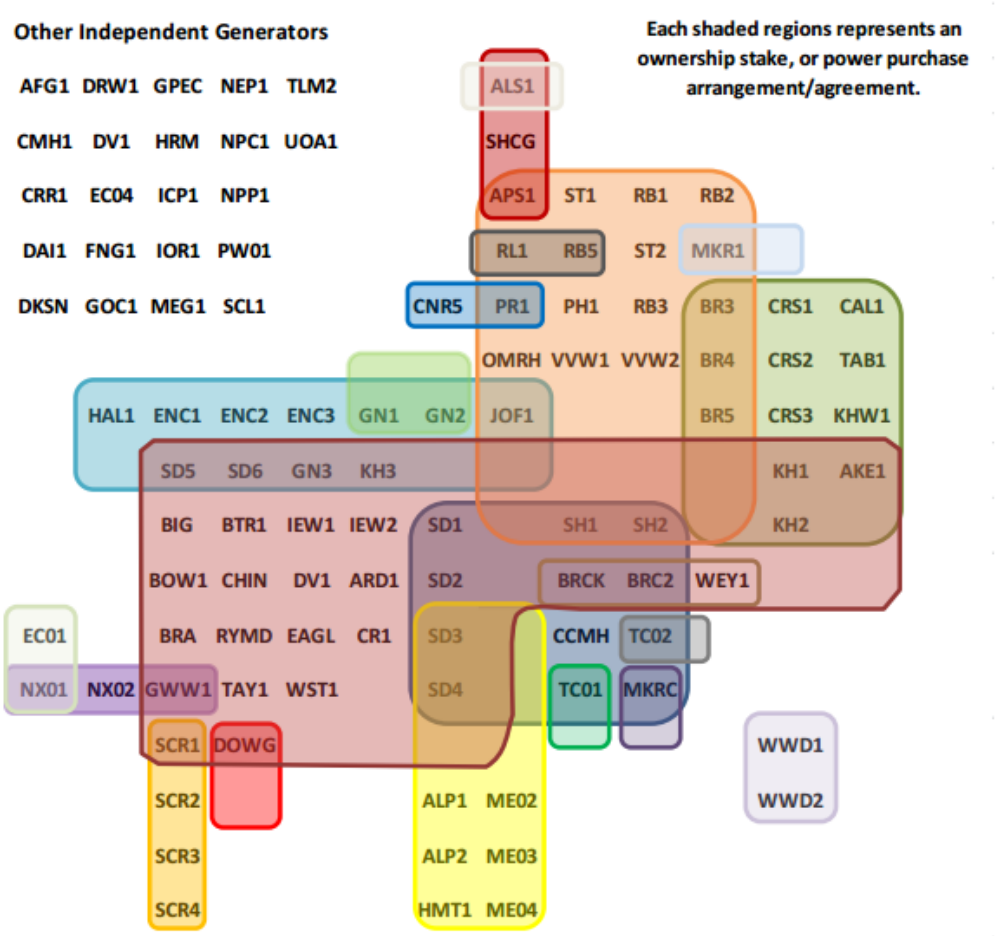
Figure 13: Market Share Estimates of Alberta's generation capacity[38]



[37] These issues have been cleared up more recently as market participants are now responsible for clarifying who has offer control over all energy that is offered into the market. See AESO Presentation on Market Share Offer Control for example.

[38] See Table 2.1 of the Alberta MSA's 2012 Market Share Offer Control report.

Figure 14: Many of the generation assets in Alberta have a number of Owners



One of the principal reasons for the inter-linkages displayed in Figure 14 is the Power Purchase Arrangements (PPAs). As discussed in chapter 2, the PPAs were a unique and important step on the deregulation path taken in the Alberta generation market. The idea of the PPA arrangements was to increase the level of competition in the generation market by removing the offer control from the PPA Owners to the PPA Buyers. To do so, the PPA contracts ensure that the market participant responsible for operating and maintaining the unit is different from the participant who offers the available generation into the market. As shown by Table 7, the thermal PPA remain a significant factor in the Alberta market, representing almost 5,000 MW of contracted thermal capacity (over a third of Alberta's total generation capacity).

In terms of offer control, the thermal PPAs are complicated because any increased capacity / excess energy on these units belongs to the PPA Owner and they have the right to offer this energy into the market if they choose. Therefore, at the majority of PPA assets, the excess energy / increased capacity is offered into the market by the PPA Owner, while the PPA Buyer has the offer control of the Committed Capacity (the capacity that is contracted under the PPA). As shown by the MSA's market share offer control reports, the Sundance A and Sheerness PPAs are the only exceptions (at these assets the committed capacity, increased capacity and excess energy are all offered into the market by the Buyer).[39]

Table 7: Thermal Units that remain under Power Purchase Arrangements[40]

PPA	PPA Owner	PPA Buyer	Units	Maximum Capability	Committed Capacity	Increased Energy / Excess Capacity
Battle River	ATCO	ENMAX	BR3	149	147.3	1.7
			BR4	155	147.3	7.7
			BR5	385	368.2	16.8
Genesee	EPCOR (Capital Power)	Balancing Pool	GN1	400	381	19
			GN2	400	381	19
Keephills	TransAlta	ENMAX	KH1	406	383	23
			KH2	400	383	17
Sheerness	ATCO (50%), TransAlta (50%)	TransCanada	SH1	390	378.1	11.9
			SH2	390	378.1	11.9
Sundance A	TransAlta	TransCanada	SD1	288	280	8
			SD2	288	280	8
Sundance B	TransAlta	TransCanada	SD3	362	353	9
			SD4	406	353	53
Sundance C	TransAlta	EPCOR (Capital Power)	SD5	406	353	53
			SD6	401	357	44
TOTALS				**5,226**	**4,923**	**303**

[39] See Tables A.1 – A.6 in Appendix A of the 2012 report for example.

[40] The structure of the Hydro PPA is different from the thermal PPAs. The offer control of the Hydro units remains with the PPA Owner, but the Owner has financial Energy and Reserve obligations to the PPA Buyer.

Another ownership issue that complicates clarifying offer control is co-generation capacity. In particular, a large amount of co-generation capacity in Alberta is owned by the larger generating companies that are heavily involved in the Alberta power market. However, the extent to which this capacity can be used to exercise market power is often meaningfully limited because of long-term contractual obligations to supply steam and/or power. As shown in Table 8, over 2,700 MW of cogeneration capacity involves this kind of ownership structure, so this consideration is important for any measure of market power.

Table 8: Long-term contractual obligations are common at co-generation assets in Alberta

Asset ID	Generation Asset	Power Company(s)	Other Company(s)	Capacity (MW)
SCR1	Suncor #1 (SCR1)	TransAlta	Suncor	901
JOF1	Joffre #1 (JOF1)	ATCO, Capital Power	NOVA Chemicals	474
DOWG	Dow Hydrocarbon (DOWG)	TransAlta	Dow Chemicals	326
MKR1	Muskeg River (MKR1)	ATCO	Shell, Chevron, Marathon	202
APS1	ATCO Scotford Upgrader (APS1)	ATCO	Shell	195
MKRC	MacKay River (MKRC)	TransCanada	Suncor	185
PR1	Primrose #1 (PR1)	ATCO	CNRL	95
TC01	Carseland Cogen (TC01)	TransCanada	Agrium	95
BCRK, BCR2	Bear Creek	TransCanada	Weyerhauser	94
RB5	Rainbow #5 (RB5)	ATCO	Husky	50
RL1	Rainbow Lake #1 (RL1)	ATCO	Husky	47
TC02	Redwater Cogen (TC02)	TransCanada	Williams Energy	46
			Total Capacity =	**2,710**

Finally, the two most recent additions to Alberta's coal fleet have both been built by means of a joint venture between TransAlta and Capital Power. Genesee #3 (450 MW commissioned in 2005) and Keephills #3 (450 MW commissioned in 2011) are both offered into the market through means of a third party, with TransAlta and Capital Power both having offer control of

half of each units capacity (AUC (2010) Decision 548). While each firm independently offers their half of the generation into the market, it is often not possible to distinguish between the offers submitted and, for the time period analyzed in this thesis, participants were under no obligations to state which company was responsible for each offered block.

3.5 Information Availability

In the Alberta electricity market the availability of market information is high relative to other electricity markets (Charles Rivers Associates (2011) "Electricity Market Data Transparency").[41] The hourly Historical Trading Report provides market participants with the market supply curve that prevailed in the previous hour.[42] The Historical Trading report shows each price quantity block that was offered into the Energy Market in the previous hour. The report is released at approximately 10 minutes into each hour. For example at 13:10 the market supply curve that prevailed in Hour Ending 13 (from 12:00 – 13:00) is made available. Given the 'T-2' rule, this effectively means that generating firms can utilize the supply curve from HE 13 (X) to inform their offer strategies for HE 17 (X+4). In addition to this, the Current Supply and Demand page allows firms to track system demand in real time and participants can also see the exact amount being produced by each generation asset in the province at any point in time. This availability of information is relevant to the thesis because it means that generating firms face very little uncertainty when deciding on their optimal offer strategy for a given hour.

[41] See http://www.aeso.ca/downloads/Market_Reports_Jan_2010.pdf for a list of the reports available.

[42] This hourly report is available, along with other market data, at http://ets.aeso.ca/.

Chapter 4: Literature Review –Market Power in Deregulated Electricity Markets

> *"[D]etecting and proving the existence of market power in electricity markets is not an easy task. Economists and regulators have yet to develop a generally accepted, standardized set of market power monitoring procedures. Rather there exists a range of tools, techniques and measures – some drawn from standard industrial organization theory, some especially developed for electricity markets – which are employed to varying degrees by different market monitors and regulators throughout the world."*
>
> *Twomey et al. (2005)*

Since the California electricity crisis economists around the world have worked to develop an accurate understanding of market power and of participant behaviour in wholesale electricity markets. Many of the approaches undertaken can be categorized as either "structural" or "behavioural". Structural indices attempt to characterize competition in the market by looking for conditions conducive to the exercise of market power. These measures do not identify the exercise of market power, but rather, the conditions that indicate that one or more suppliers possess the ability to exercise market power. In contrast, behavioural examinations look for evidence of the actual exercise of market power by examining the conduct of suppliers.

In addition, economists have also used simulation methods to analyze the extent of market power in wholesale electricity markets. These simulated methods generally involve using Industrial Organizational theory to simulate competitive market outcomes, and these competitive results can then be compared to the realized market outcomes.

This section provides a detailed review of how each of these approaches has been used to analyze market power in electricity markets. The section begins by discussing the variety of

structural and behavioural indicators that have been used to examine market power, and then moves onto discuss how the market simulation approaches have been utilized. For each methodology discussed, I provide an outline of the intuition, the main pros and cons involved, and review some prominent and relevant academic papers to the extent that they are applicable. Since the objective of the thesis is to analyze structural market power in the Alberta electricity market, particular attention is paid to papers that analyze structural market power and/or market power in the Alberta wholesale electricity market.

4.1 Market Concentration Measures and 'the Relevant Market'

Concentration measures are simple scalar metrics that measure the concentration of suppliers in a defined market. Measures of market concentration are widely use within competition law to analyze and make inferences regarding structural market power. The two most commonly used concentration indices are market shares and the Herfindahl-Hirschman Index (HHI).

Once the relevant market is defined, the calculation of market shares is straightforward. A company's market share is given by the firm's percentage of the total market:

$$MS_i(\%) = \frac{C_i}{\sum_{i=1}^{N} C_i} * 100$$

Where *MSi* is the Market Share of Firm i at time t, *Ci* is the capacity controlled by firm I, and the denominator is the total capacity within the market.

To make inferences regarding overall market competition, as opposed to analyzing the market power of a single firm, market shares are often aggregated to report Concentration Ratios.

Concentration ratios are percentage statistics showing the total market share controlled by the largest *n*-number of participants. For instance, the four-firm Concentration Ratio (CR4) would detail the total market shares of the largest four firms. No particular guidance is given on the "correct" value of *n*, although CR4 and CR8 measures are commonly used to compare industries.

Concentration Ratios are often criticized because they do not account for the relative distribution of market shares. In particular Concentration Ratios will not consider the relative sizes of the leading firms, nor will they indicate the distribution of smaller firms that are not included in the calculation. In recognition of these deficiencies, competition authorities such as the US Department of Justice and the Federal Trade Commission place more emphasis on alternative measures of overall market concentration; notably the Herfindahl-Hirschman Index ("HHI"). The HHI is defined as the sum of the squares of market shares for all (N) firms within the relevant market.

$$HHI = \sum_{i=1}^{N} (MS_i)^2$$

Where *MSi* is the market share of firm i.

A higher HHI is indicative of greater market concentration. The HHI is bounded by 0 (an infinite number of negligible firms) and 10,000 (a single firm). The HHI will increase if there are fewer firms in the market and/or if there is a greater variation in the distribution of market shares.

The economic justification for using market concentration metrics to measure market power is that a company's profit is maximized in a Cournot Equilibrium when the price-cost margin is

proportional to the market share of the company, and inversely proportional to the price elasticity of market demand:

$$\frac{(p - mc)}{p} = \frac{s_i}{\varepsilon}$$

The underlying intuition here is that as the market share of a particular firm increases, the ability of its competitors to respond to price changes will generally fall. Larger firms will often face less supply-side competition and consequently larger firms will have a greater ability to exercise unilateral market power. In contrast, a firm with low market share will typically face greater competition as its rivals are larger and more able to increase supply as price rises. All else equal, a smaller firm trying to raise the market price by withholding output will face a greater supply response as prices rise, and the firm will have less unilateral market power as a result.

To calculate any measure of structural market power requires a definition of the relevant market. This involves determining the relevant product(s) in the market as well as the geographic boundaries of the market. The product definition involves determining which products are demand-side substitutes, and the geographic dimension involves determining the locations of competing firms that produce the same product; supply side substitutes (Church and Ware (2000)).

In many industries, the choice of relevant products and locations are contentious issues because these definitions can have significant effects upon the implications of market concentration analysis. A market that is too 'narrow' excludes substitutes that impose important competitive constraints and will lead to concentration measures that overestimate the ability of firms to exercise market power. Conversely, a market definition that is too 'broad' will yield

concentration metrics that underestimate the market power of firms since the market includes products and production locations that are not close substitutes and do not exert meaningful competitive constraints (Church and Ware (2000)).

Given that electricity is a homogeneous good with no reasonable substitutes, defining electricity as the sole product is a fairly innocuous assumption. However, due to the unique characteristics of electricity, electricity markets are distinguishable by time and location (Twomey et al. (2005)). In addition, it is clear that capacity, as opposed to energy production, is the correct measure to be used in power markets. As noted by Borenstein et al. (1999), using energy-sales to calculate market concentration is fundamentally misguided since the very act of exercising market power involves reducing energy-sales. Hence, if relatively large firms exercise unilateral market power and the withheld output is replaced by smaller firms, the exercise of market power results in a decrease in market concentration.

In terms of delineating the geographic bounds of power markets there are two major approaches used. The first approach, utilized by the Canadian Competition Bureau and by the US competition authorities, defines the boundaries of an anti-trust market by considering whether a hypothetical monopolist would profitably implement a Small but Significant Non-transitory Increase in Price ("SSNIP"). In the Merger Enforcement Guidelines the Competition Bureau notes:

> Conceptually, a relevant market is defined as the smallest group of products, including at least one product of the merging parties, and the smallest geographic area, in which a sole profit-maximizing seller (a "hypothetical monopolist") would impose and sustain a small but significant and non-transitory increase in price ("SSNIP") above levels

> that would likely exist in the absence of the merger. In most cases, the Bureau considers a five percent price increase to be significant and a one-year period to be non-transitory. Market characteristics may support using a different price increase or time period.

Using the SSNIP analysis to define the relevant anti-trust market can be a non-trivial task in electricity markets. In particular, depending on the prevailing supply and demand conditions, as well as on the state of the transmission system, the ability to supply power from one geographic area to another may be severely limited at certain times and less so at others. Therefore, the relevant anti-trust market can vary according to the prevailing market fundamentals, including the degree of congestion of the transmission system, which in turn may depend upon the actions taken by market participants.

The second approach to defining the relevant market is more straightforward. This approach defines the relevant economic market using the classical "law of one price" test. Using this method the relevant economic market is defined as the geographic location within which the same thing is sold for the same price at the same time, with allowance being made for transportation costs (Twomey et al. (2005)). The underlying principal here is that the boundaries of an economic market should include all the firms and their products that interact to determine prices.

If the geographic bounds of the market are delineated using the Law of One Price method, this yields a fairly straightforward geographic boundary for electricity markets. Although the remaining clarifications include whether all market capacity, in particular variable capacity (such as wind or hydro) should be treated as equivalent to more-definitive thermal capacity (coal and

gas-fired units), and whether the Available Transmission Capacity (ATC) of intertie connections and behind-the-fence capacity should be included as part of the relevant market.

Once the relevant market is determined, concentration measures are simple to calculate and easy to comprehend. However, even with a clear and accurate definition of the relevant market, there are still a number of important factors which are not accounted for by measures of market concentration when analyzing electricity markets. Indeed, it is widely recognized that concentration measures are limited in their ability to analyze the extent of competition in power markets: "the generic weaknesses of diagnosing market power with concentration measures are magnified in the electricity industry" (Borenstein, Bushnell and Knittel (1999)).

To understand why market concentration measures are an inappropriate tool for analyzing the market power of suppliers in wholesale electricity markets, it is necessary to reiterate that electricity markets are unique in a number of important ways. In particular, electricity is very costly to store, its production is subject to severe capacity constraints, and it must be delivered through a transmission network with finite capacity, all of which limit the magnitude of the supply response to a firm's unilateral attempts to profitably raise prices (Wolak (2010)). In addition, unit outages and the characteristics of generation capacity will both play a critical role in determining the extent of competition in power markets. A simple calculation of concentration measures based on market capacity figures will therefore fail to capture any semblance of a relevant market. Finally, the real-time wholesale demand for electricity is variable and close to perfectly price inelastic. A central criticism of simple market share calculations is that they do not consider variations in market demand, which can be critically

important in electricity markets given the inability to store electricity and arbitrage its use across time.

As a result of these market characteristics, market concentration measures are frequently criticized for yielding erroneous conclusions when analyzing market power in electricity markets. There's no better example of this than the California electricity market during 2000 and 2001 when the state famously went into an energy crisis. In this period, the Federal Energy Regulatory Commission (FERC) had established a market power threshold using market shares. In particular, any firm controlling greater than 20% of the relevant market was not permitted to receive market based (as opposed to cost-of-service) rates. As noted by Sheffrin (2001):

"The current safe-harbor of 20% market share is not an adequate test for the ability to exercise market power. Under certain definitions of the relevant market, no single supplier in California has a 20% market share yet no one can call our markets workably competitive. At numerous times during the past two years, suppliers with less than a 10% share have been able to influence unduly the market clearing price."

These results are supported by the calculations of Blumsack and Lave (2002) who estimate a HHI for the deregulated California market of 664. Blumsack and Lave also calculate the HHI for the electricity markets in PJM and New York, concluding that:

> "Conventional measures of market structure used by economists, such as the Herfindahl Hirschman Index (HHI), give a misleading picture of the competitiveness of electric power markets, since these metrics do not consider the special properties of electricity as a commodity… Our analysis of pivotal oligopolies in California, PJM, and New York

finds that all three of these markets are far less competitive than their HHIs would suggest."

Despite the inherent flaws with the use of simple market concentration metrics, they remain widely used within electricity markets to analyze generator market power. For example, FERC continues to use a 20% market share threshold as a screening tool for market power when determining whether a participant can receive market based rates. However, this calculation is now used as one of two screening mechanisms, with the second being a Residual Supplier Index analysis.

In the Alberta electricity market, market shares are used within the Fair, Efficient and Open Competition (FEOC) Regulation. Section 5: 'Market Share Offer Control' of this Regulation, specifies that no supplier can control more than 30% of the generation capacity within the Alberta market. The underlying market definition makes no distinction between the generator types within the Alberta market and does not include the capacity available on the interties, a principal factor in market competition. In addition, the market definition does not consider any measure of prevailing market demand and thus cannot speak to the relative tightness of the market.

4.2 The Residual Suppler Index

The Residual Supply Index ('RSI') is an improvement over market concentration calculations because it incorporates demand conditions, in addition to supply conditions, in a measure of structural market power. The RSI is an intuitive measure of structural market power that

calculates the extent to which a particular firm is pivotal to the clearing of the electricity market. The RSI for firm *j* at time *t* is calculated as follows:

$$RSI_{jt} = \frac{(Total\ Market\ Capacity_t - Capacity\ Controlled\ by\ firm\ j_t)}{Market\ Demand_t}$$

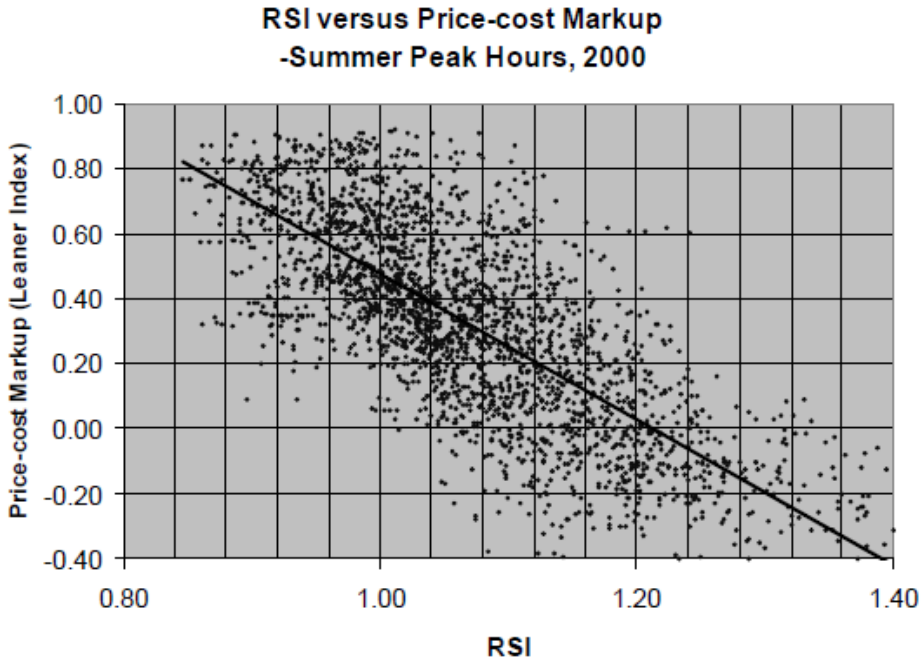
Lower values of the RSI are indicative of greater market power since lower values imply that the ability of other firms to meet the prevailing market demand is less. RSI values of less than 1 indicate that the relevant participant is pivotal (i.e. its generation is required to meet prevailing demand). Indeed, a binary variant of the RSI, the Pivotal Supplier Indicator ('PSI'), is often used to analyze market power. The Pivotal Supplier Index (PSI) is a binary indicator for a supplier at a given point in time (usually hourly) which is equal to one if the supplier is pivotal and zero if the supplier is not pivotal. The PSI can then be analyzed over an extended period of time to determine the frequency with which a supplier is pivotal.

The RSI is a refinement over the PSI because the RSI illustrates the extent to which a supplier is pivotal rather than simply whether the supplier is pivotal or not. In practice, the difference between a supplier being pivotal and not pivotal may be 1 MW of capacity or a minute variance in market demand. While the RSI would highlight little difference between two such scenarios, the PSI would reflect that in one the firm had market power while in the other it did not.

The structural RSI measure can be adjusted to account for the incentives a firm has to exercise market power by considering its forward sales (FS) and forward purchases (FP) of electricity:

$$RSI_{jt} = \frac{\left(Total\ Market\ Capacity_t - Capacity_{jt} + (FS_{jt} - FP_{jt})\right)}{Market\ Demand_t}$$

The RSI was initially developed by the California Independent System Operator (CAISO) as the inadequacies of using market shares to analyze market power were becoming apparent. Empirically, the RSI was used successfully to predict actual market power as measured by the price-cost mark-up (the Lerner Index). In particular, CAISO's analysis of hourly market data found a significant relationship between the 'market RSI'[43] and the Lerner Index realized in the California market. The relationship (illustrated in the Figure below) indicates that on average a market RSI of about 1.20 would result in a market price outcome close to the competitive market bench-mark, although a significant amount of variance is notable (the Figure is taken from Sheffrin 2001):



[43] The market RSI is the Residual Supplier Index for the largest supplier at that point in time.

Wolak and McRae (2012) use the Pivotal Supplier Index (PSI) metric to analyze the behaviour of suppliers in the New Zealand market between January 1st 2001 and June 30th 2007. In particular, Wolak and McRae (2012) illustrate a statistically significant relationship between a firm's PSI and its marginal offer price[44] for each of the largest four suppliers in the New Zealand market. Wolak uses econometrics analysis to hold factors affecting the opportunity costs of producing electricity constant; fossil fuel input prices and daily (hydro) water levels are the two principal independent variables highlighted.

In addition, Wolak and McRae (2012) use detailed (non-public) data on long-term financial sales and purchases to calculate a Net Pivotal Supplier Index. This Net Pivotal Supplier analysis determines whether a supplier is pivotal to the New Zealand market for a given half-hour after accounting for the supplier's fixed-price forward market obligations. Using a similar econometric analysis to that outlined above, Wolak illustrates the importance of these fixed-price forward market obligations by highlighting a more significant relationship between each firm's Net Pivotal Supplier Index and its offer behaviour in comparison to each firm's Pivotal Supplier Index and its offer behaviour.

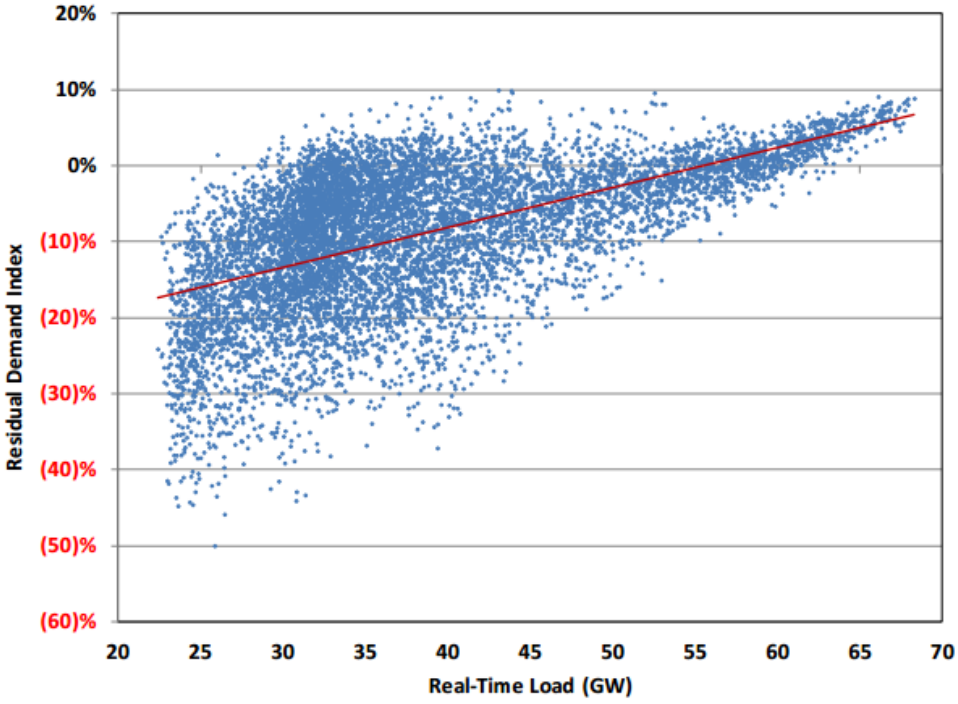
Given the proven inability of market shares to account for the dynamic nature of electricity markets it is unsurprising that the Residual Supplier Index (RSI) and the Pivotal Supplier Index (PSI) are now widely used to analyze market power electricity markets. Notably, the PSI is now used by FERC alongside the 20% market shares test as a screening mechanism for market power. If a supplier fails either test it has a rebuttable presumption of market power. A supplier passes

[44] A firm's marginal offer price is defined as the highest price offer block that is dispatched.

the PSI test if demand can be met without any contribution to supply by the applicant or its affiliates.

In addition to their adoption by FERC, variants on the PSI and RSI are widely used by market monitors and industry analysts. For example, Potamac Economics uses the Residual Demand Index ('RDI'), a statistic that measures the percentage of load that could not be satisfied without the resources of the largest supplier, to analyze structural market power in the Electric Reliability Council Of Texas (ERCOT). When the RDI is greater than 0 the largest supplier is pivotal. The Figure below is taken from the 2011 ERCOT State of the Market Report and illustrates the relationship between the RDI and real-time load in Texas.

Figure 69: Residual Demand Index



In the Pennsylvania New Jersey Maryland ('PJM') Interconnection[45] the RSI index is used to determine whether the market is structurally competitive in the event that transmission constraints restrict the extent of supplier competition in meeting certain local demand pockets. The Three Pivotal Supplier ('TPS') test measures the extent to which groups of three firms are, on aggregate, pivotal to the market in its need to relieve the system congestion. A test failure indicates that structural market power exists and the relevant firms will be mitigated to cost-based offers in the event that their generation is started in order to relieve the constraint. In its 2012 State of the Market Report Monitoring Analytics highlights that "analysis of the application of the Three Pivotal Supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive." (Monitoring Analytics (2012))

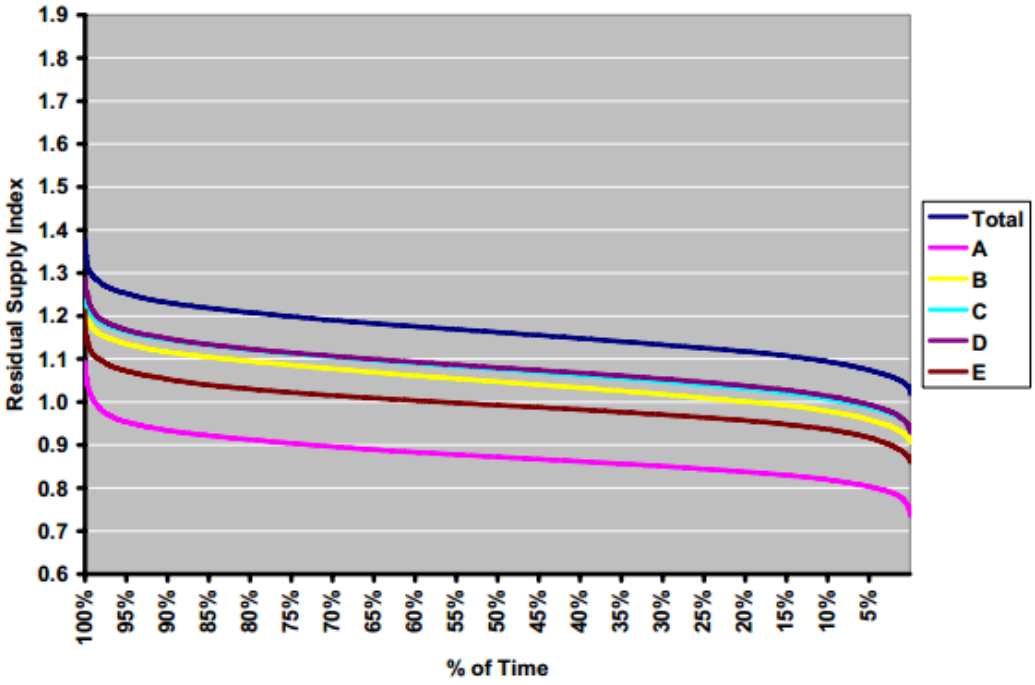
It is important to put the use of the RSI metric in the PJM Interconnection into context. While Alberta's electricity market is 'energy only' the PJM Interconnection contains a capacity market (auction) through which generators receive additional revenues to cover the fixed and sunk costs associated with developing electrical generation capacity. In Alberta no capacity market exists and instead existing generators and potential entrants rely heavily on energy market prices to recover their investments (see section 3.1).

The market monitor in Alberta (the Alberta MSA) first introduced the Residual Supplier Index in a 2006 report on Market Concentration Metrics. As shown below, the RSI implies that a

[45] The PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

significant amount of structural market power was present in the Alberta market with the largest participant being pivotal (an RSI of less than 1) for the vast majority of hours.

Figure 2.4: Duration Curve showing Residual Supply Index for Five Participants (based on offered energy, Jan. 2005 – May 2006)



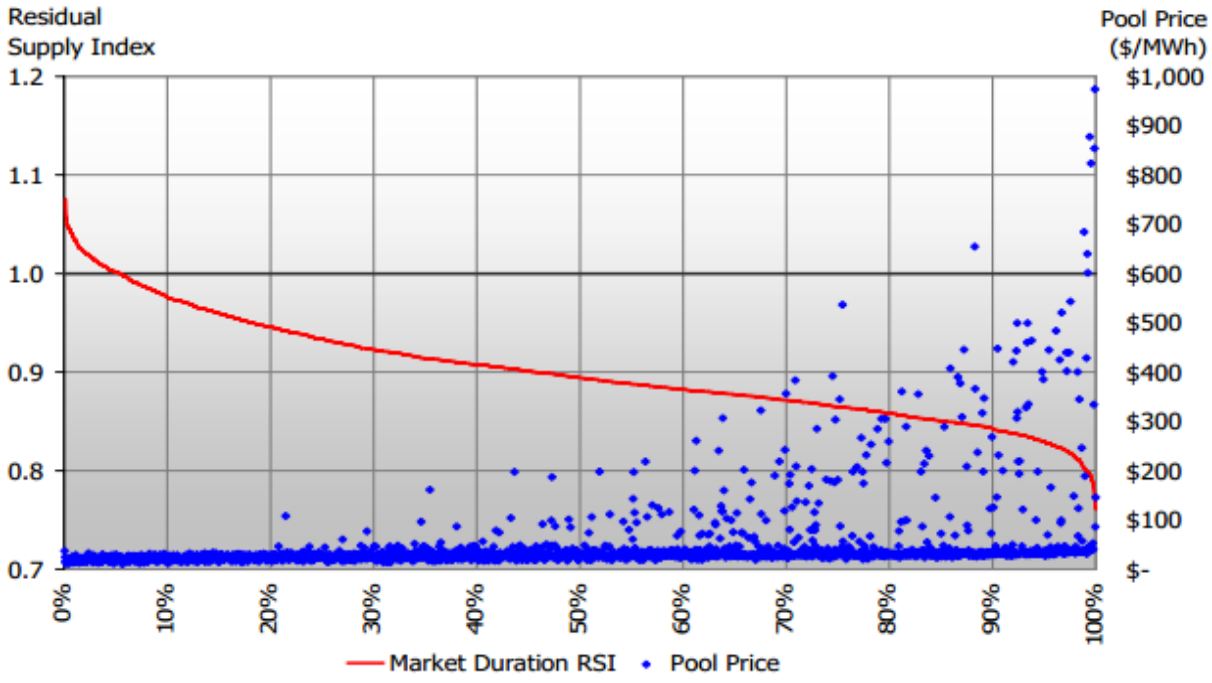
The MSA updated its RSI analysis once again in its 2010 Q4 quarterly report. As shown by the summary statistics provided in Table 2.1 (reproduced below) the energy market continued to be concentrated and the market RSI illustrates that in 2010 the largest supplier in a given hour was pivotal to the market in 90-95% of hours. In addition, the RSI metric illustrates that in some hours the supply controlled by other firms was less than 80% of market demand, illustrating that the largest supplier was significantly pivotal in these hours.

Table 2.1: Market RSI Results – 2010 Quarterly Summary

	Q1/10	Q2/10	Q3/10	Q4/10
% Time Market Pivotal	95%	89%	89%	95%
Average Market RSI	0.91	0.91	0.91	0.90
Max Market RSI	1.10	1.19	1.18	1.08
Min Market RSI	0.77	0.75	0.76	0.76

However, as illustrated by the Figure below (Figure 2.2 from the MSA's Q4 2010 report) the link between the largest firm being pivotal to the energy market and the resulting market price is weak. For instance, the Figure shows that the largest supplier is pivotal (RSI is less than 1) in ~95% of the hours and yet the majority of pool prices in this period cleared at well below $100.

Figure 2.2: Market RSI vs. Pool Price - Q4/10



There are two principal reasons why the market RSI is not more correlated with market outcomes in Alberta. Firstly, the RSI is a structural measure of market power and does not account for firm incentives. The extent to which a firm can profitably exercise any available market power in the real-time market will depend upon the firm's net exposure to the real-time pool price (this is discussed in greater detail in section 5.3). The two largest companies in the Alberta market both hedge their generation capacity through fixed-price forward contracts; TransCanada has numerous cogeneration facilities where a portion of the power is sold through long-term contracts, while ENMAX contracts a significant amount of its generation through fixed-price sales in the retail market.

In addition to hedging their generation, it is important to highlight that must-run obligations are an important factor for the larger generators in Alberta. For example, at coal-fired units, the entire generation capacity is not easily withheld because coal units cannot operate safely below a certain generation level (this 'minimum stable generation' is normally in the range of 30-40% of a unit's total capacity) and coal units are prohibitively expensive to shut-down and start-up. A firm with a large amount of must-run capacity could have a low RSI, but in practice have little ability to move market prices.

The important point to make here is that while the RSI metric may highlight the extent to which a firm's capacity is pivotal to the energy market, it does not in any way indicate the costs associated with withholding this capacity. A firm may optimally avoid exercising market power if it is operationally expensive or if the strategy would be unprofitable because of a firm's fixed-price sales. While important, this latter critique can be directed at any structural measure of

market power and, as noted above, the RSI can be adjusted to account for such incentives if this data is available.

On a similar note, while the RSI considers the aggregate amount of competing capacity facing a firm, this aggregate measure may not fully reflect the extent to which this competing capacity constrains the firm's ability to exercise market power. Firstly, the RSI does not differentiate one generation fuel type from another even though there may be a substantial difference in the extent to which the capacity is competitive. For example if 200MW of a competitor's coal-fired capacity is unavailable, this will tend to be more significant in terms of increasing the firm's ability to exercise market power than if 200 MW of a competitor's hydro capacity is unavailable because hydro capacity has a finite fuel supply and runs at a lower capacity factor than coal. The RSI metric however would fail to distinguish between the two scenarios.

In addition, there can also be an important distinction between generation within fuel types depending on ownership or offer control. For example, while the Genesee and Sheerness assets are both coal fired generators with ~400 MW of capacity, it is rare for any available capacity at Genesee to be withheld from the market, whereas capacity at the Sheerness assets is often offered at high prices during peak times. Therefore, an outage at Genesee will tend to be more significant in terms of its effect on the level of competition at peak times than an outage at Sheerness.

4.3 Residual Demand Analysis

Because total supply must exactly equal total demand at every point in time, electricity markets necessitate the Independent System Operator having access to detailed offer data illustrating the willingness-to-supply function of every generator in the market. As a result, this type of detailed offer information is often publicly available in electricity markets whereas this type of information would be considered commercially sensitive in other markets, and is therefore seldom available.

Using this price-quantity offer data allows one to accurately construct the *ex-post* aggregate market supply function. Removing a given firm's offers from the market supply function yields the aggregate willingness-to-supply of the firm's competitors. Subtracting this 'supply of other firms' function from the market demand function[46] yields the *ex-post* residual demand function that was faced by a supplier at a given point in time (see section 5.1 of the thesis for illustrations and further discussion). The slope and size of a firm's residual demand function can then be analyzed to make useful inferences regarding market power.

A principal advantage of using the residual demand function to analyze market power is that it directly considers both the aggregate amount of competing capacity facing a firm and the manner in which this competing capacity is offered into the market by rival firms. By considering the offer prices at which rival firms submit their available generation, the residual demand analysis directly tackles the weaknesses of the RSI metric that are discussed above.

[46] Given the inelastic nature of demand in electricity markets, the demand function is typically assumed to be vertical although this is not a necessity and the residual demand analysis can be tailored to account for price-responsive loads who do not directly submit their bids into the market.

As with the RSI metric, the Residual Demand function can be adjusted to account for forward fixed-price sales and purchases, and other factors that will impact the incentives a firm has to exercise market power. For example, the impact of a firm selling 100 MW of power month-ahead at a fixed price is to reduce the firm's exposure (i.e. net sales) to the real-time price of electricity by 100 MW. Therefore, the residual demand function for the firm can simply be shifted to the left to reflect the fact that the firm's sales into the market are 100 MW less at all price levels. Conversely, a firm that buys 100 MW of power at fixed prices has an increased amount of sales into the real-time market, and its residual demand function will shift right for all prices. While the execution of this analysis is straightforward, obtaining the required data is difficult because of commercial confidentiality.

A practical issue with analyzing a firm's Residual Demand function is estimating its slope. Estimating the slope of the function requires a first-difference approach because the residual demand function is a step-function due to the fact that firms submit their available capacity in blocks. More importantly, one must decide upon which region of the residual demand function is relevant. Given that a firm's profits are maximized by consideration of marginal revenues, it is apparent that economic theory highlights the area surrounding the market clearing point ('the margin') of the residual demand function to be the relevant area. In practice, whether the relevant area is 50 MW above and below the market equilibrium or 200 MW above and below is an exercise of judgment. In their analysis of the New Zealand market, Wolak and McRae (2012) address this issue by using a variety of methods to estimate the slope of a firm's residual demand function, and highlight that the choice of method is largely irrelevant from an econometric stand point because the resulting estimates are all highly correlated with one another.

While focusing on the marginal area of a firm's residual demand function is intuitive from an economic theory standpoint, it can raise some issues when analyzing market power in practice. In particular, consider a situation in which a number of suppliers independently exercise unilateral market power and raise their offer prices to similar levels in order to set market prices well above prevailing variable costs. In this type of scenario, a firm's residual demand function will be relatively flat at the margin, implying the firm has relatively little ability to exercise unilateral market power. However, given that the firm is setting market prices well above variable costs, the conclusion of little market power is not intuitive.

Another critique of the residual demand approach is that it does not consider the costs involved with a firm exercising unilateral market power. These costs are two-fold; operational costs and opportunity costs. The operational costs associated with exercising market power will be high if it involves shutting down and restarting generators (particularly baseload generators), or if it requires varying generation levels at an inflexible unit, where this 'ramping' operation is expensive. The opportunity costs of exercising market power are generally given by the margins that are foregone by withholding the generation.[47] Therefore, the opportunity costs involved with the exercise of market power will be lower for generators which have a higher prevailing variable cost.

Given that the Residual Demand analysis does not consider the generation portfolio of the participant being analyzed, it cannot account for the costs associated with the exercise of market power and how this might vary from one firm to another; or from one point to another within a

[47] The major exception here is hydro generation; because the fuel supply (water) at hydro generators is finite, the opportunity costs associated with using the water now are the future revenues that are foregone because the water is no longer available.

particular firm's supply function. While this critique is focused on firm incentives, and can be directed at any structural measure of market power, the costs involved with the exercise of unilateral market power are nonetheless an important factor in analyzing the ability of firm's to profitably exercise unilateral market power.

Wolak (2000) uses the Residual Demand analysis to analyze the behaviour of a major generator in the first three months of the National Energy Market in Australia. In particular, Wolak (2000) uses the Residual Demand approach, in combination with the generator's own financial hedge position, to inform the short-run profit maximizing behaviour of the supplier. Using this analysis Wolak calculates that the variable profits from the best-response price-setting strategies (calculated *ex-post*) for the firm were 11%-17% higher than the variable profits that the firm realized using its actual bidding strategies, with the estimated range being dependent upon the marginal costs that were assumed.

In addition, Wolak uses the analysis to highlight the importance of a firm's forward contract position on the firm's best-response price and quantity outcomes. Firstly, Wolak discusses the importance of forward contracting on the firm's bidding behaviour, noting that a generator that is 'oversold' (i.e. buying from the market) will optimally offer so that its generation is dispatched at prices lower than marginal cost in an attempt to lower prices. As well, Wolak (2000) highlights that the difference between a firm's optimal price-quantity outcome without contract cover and the firm's optimal price-quantity outcome with contract cover will vary importantly depending upon the elasticity of the firm's residual demand function:

"A less elastic demand implies a more steeply sloped residual demand function and therefore a greater divergence between the best-response-price without contract cover and best-response

price with contract cover, and a smaller divergence between Firm A's production at these two prices. Conversely, a more price elastic residual demand function implies a smaller divergence between these two prices and a greater divergence between Firm A's sales with and without contract cover."

Using this intuition, Wolak explains the rationale behind firm offer behaviour and the resulting low prices that were observed in the first three months of the National Energy Market. Since the market's generation capacity was high relative to observed market demand, the larger suppliers in the market faced relatively elastic residual demand functions during this period. In response to foreseeing these fundamentals, each of these firms hedged their generation capacity through forward contracts to ensure that their generation was sold at profitable prices. Had one of the generators avoided selling capacity forward, the firm would optimally have set market prices at a slightly higher level, although the firm would have sold substantially less generation. As a consequence of this trade-off, each of the large firms in the NEM contracted their capacity to avoid the risks associated with low prices and a lack of sales in the real-time market. In turn, this forward contracting caused the larger generators to offer more aggressively, further increasing competition, and increasing the incentives of other generators to do likewise and hedge their capacity.

Wolak (2003) uses a residual demand analysis to measure the incentives that each of the five largest generators in California had to exercise market power in the state's wholesale market in the summer months (June through September) of 1998, 1999 and 2000. In particular, Wolak (2003) uses data on the bids submitted to the CAISO real-time energy market in order to estimate the hourly *ex-post* elasticity of each firm's residual demand function at the market clearing price.

Using this analysis, Wolak (2003) illustrates that the ability of the largest five suppliers to exercise market power was substantially higher in the summer of 2000 than in the summer of 1999 or 1998, and that their market power was slightly higher in 1998 relative to 1999: "the enormous increase in the amount of market power exercised in the California market beginning in June of 2000 was due to the substantial increase in the amount of unilateral market power possessed by each of the five large suppliers."

In addition, Wolak (2003) clarifies that his results show that coordinated actions by the larger suppliers were unnecessary to bring about the substantial price increases that occurred during in California during the summer of 2000. That is, Wolak (2003) highlights that the resulting market prices were consistent with each of the largest suppliers behaving unilaterally, with each firm maximizing its expected profits in response to the bidding behaviour of all other suppliers.

In the same vein as their Pivotal Supplier Index (PSI) analysis, Wolak and McRae (2012) also use residual demand analysis to measure the ability of suppliers in the New Zealand market to exercise unilateral market power from January 1st 2001 to June 30th 2007. In particular, the authors use detailed half-hourly offer and demand data to construct the *ex-post* residual demand function for each of the largest suppliers in the New Zealand market. Using these functions, Wolak and McRae (2012) estimate the inverse semi-elasticity of each firm's residual demand function for every half-hour settlement interval within the sample period. This inverse semi-elasticity measure is calculated as follows:

$$\eta = \frac{-1}{100}\frac{\partial RD}{\partial P}RD$$

Where η denotes the inverse semi-elasticity of the firms residual demand, *RD* is the firms realized residual demand and $\frac{\partial P}{\partial RD}$ is the slope of the firm's residual demand function.

The inverse semi-elasticity of a firm's residual demand function provides a dollar estimate of the firm's ability to increase the market price with 1% of its dispatched generation. The authors also use confidential trading data for each of the firms to analyze the incentives that each of the large four suppliers had to exercise market power given its fixed-price contracted sales (Q^C):

$$\eta^C = \frac{-1}{100}\frac{\partial RD}{\partial P}(RD - \mathrm{Q}^C)$$

Using these measures, Wolak and McRae (2012) show that each of the largest suppliers in the New Zealand market exercises market power by submitting higher offer prices when the firm has the ability (or incentive) to influence market prices by doing so. In particular, Wolak and McRae (2012) illustrate a statistically significant relationship between the inverse semi-elasticity of a firm's residual demand function and the firm's 'marginal offer price'[48] for each of the largest four suppliers in the New Zealand market. The authors use panel-data econometrics, and fixed-effects techniques, to hold the opportunity costs of producing electricity constant. In conclusion, Wolak and McRae (2012) state: "We find that when each of the four suppliers has a greater ability or greater incentive to exercise unilateral market power, they submit substantially higher offer prices for a pre-specified quantity of energy... Therefore, the ability and incentive of large suppliers to exercise unilateral market power are important determinants of the supply conditions that determine short-term wholesale prices, even after the impact of exogenous factors such as water availability and fossil fuel prices have been taken into account."

[48] A firm's marginal offer price is defined as the highest price offer block that is dispatched.

Residual demand analysis has also been applied to the Alberta wholesale electricity market by Williams (2002) and by Wolak (2012). Williams (2002) used data provided by the Alberta Power Pool to analyze the extent to which the aggregate market power held by the 'strategic generators' determined market outcomes in the first eight months of the markets operation (from January 1st through August 31st 2001).

Williams (2002) defined 'strategic generators' to include all suppliers controlling above 150 MW of generation capacity, with the exception of the Balancing Pool (a government agency whose mandate prevented the organization from acting in a strategic manner). The strategic generators comprised a group of eight corporate entities controlling a total of 16 generation assets. Williams highlights that on average the strategic generators controlled 3,950 MW of capacity in each hour, which represented 65% of the average hourly market demand observed within the sample period. The Balancing Pool and market participants with less than 150 MW were termed 'non-strategic' generators, meaning that these generators were assumed to act as price-takers.

With the distinction between strategic and non-strategic generators in place, Williams (2002) analyzed the market power held by the strategic generators on an aggregate basis (i.e. as a group) by constructing the *ex-post* residual demand function faced by the strategic generators. This *ex-post* residual demand for the strategic generators was constructed by subtracting the aggregated offers submitted by the non-strategic generators away from the realized market demand. Having constructed the residual demand function faced by the strategic generators Williams (2002) then used a (10 or 20 point) running average smoothing method to estimate the slope of the residual demand function (a step function) at the market clearing price. The estimated slope is then

multiplied by the quantity of generation sold by the strategic generators to obtain an estimate of structural market power:

$$SlopeQuantity = \left(\frac{\partial P}{\partial Q}\right) q$$

Where $\left(\frac{\partial P}{\partial Q}\right)$ is the estimated slope of the residual demand function of the Strategic Generators and q is the residual demand of the strategic generators in the market clearing equilibrium.

Using the resulting 'SlopeQuantity' market power metric, Williams (2002) undertakes the following regression analysis to estimate the extent to which changes in the market power of the strategic generators had an influence on the resulting market prices, holding the daily price of natural gas, the day-ahead forecast demand and the prevailing temperatures constant:

$$Pool\ Price_t = \alpha + \beta_1 NatGas_t + \beta_2 ForecastDemand_t + \beta_3 Temperature + \beta_4 SlopeQuantity + \varepsilon_t$$

Williams uses two estimates for the slope of the strategic generator's residual demand function (one using a 10 point and the other using a 20 point running average smoothing method) and uses these estimates to inform the regression results for three different datasets within the sample period. The results are reported in Table 6.1, which is reproduced below:

Table 6.1: Regression results of equation (4), using the complete dataset and two restricted datasets.

	Estimate	Std. Error
Unrestricted		
SlopeQuantity 10	-0.002345	0.0000615
SlopeQuantity 20	-0.004939	0.0000823
Weekday Restriction		
SlopeQuantity 10	-0.002373	0.0000778
SlopeQuantity 20	-0.005512	0.0001075
High Demand Restriction		
SlopeQuantity 10	-0.0021375	0.0001106
SlopeQuantity 20	-0.0052309	0.0001593

By evaluating these regression results at their respective sample means, Williams (2002) estimates that 11% - 16% of the average pool price was caused by the strategic generators taking advantage of profitable market conditions (see Table 6.2 below). William (2002) highlights the results to be intuitive because they indicate that the strategic generators were more able to take advantage of market conditions during the weekdays and during the high demand periods.

Table 6.2: Estimates Evaluated at their sample means listed in terms of dollars. Percentage of the average Pool Price in parenthesis.

	Unrestricted	Weekday Restriction	High Demand Restriction
SlopeQuantity 10	$9.48 (11%)	$9.99 (11%)	$11.99 (11%)
SlopeQuantity 20	$11.04 (12%)	$12.79 (14%)	$16.60 (16%)

Wolak (2012) uses data from the Alberta Electric System Operator (AESO) to examine how the offer behaviour of the largest five firms in the Alberta market responds to changes in their ability to exercise unilateral market power from January 1st 2009 to December 31st 2011. Wolak (2012) then uses this analysis to estimate the benefits that additional transmission capacity has for

Alberta consumers. In particular, Wolak's analysis estimates the impact that additional transmission capacity might have on increasing competition in the Alberta wholesale market and, in turn, the impact that this increased competition might have on lowering market prices.

To measure the market power of the five largest suppliers in Alberta Wolak (2012) estimates the hourly inverse semi-elasticity of each firm's *ex-post* residual demand function. This *ex-post* residual demand function uses the realized Energy Market Merit Order and therefore accounts for any constraints on the supply-side that are the result of transmission congestion.

Using these hourly estimates of market power, Wolak (2012) undertakes a similar econometric analysis to Wolak and McRae (2012). In particular, Wolak (2012) uses regression analysis to determine the extent to which a firm's marginal offer price changes with its ability to exercise unilateral market power. The econometric analysis controls for day-of-sample and hour-of-day fixed-effects in order to control for variations in input prices. However, the econometric analysis used by Wolak (2012) does not control for which generation unit in a firm's portfolio is setting the firm's marginal offer price.

Wolak (2012) uses the results of this econometric analysis to inform how each of the largest suppliers in the Alberta market would have behaved in the event of reduced transmission congestion. More specifically, the approach taken by Wolak (2012) is summarized by the following three-step procedure:

1. A no-congestion residual demand curve is constructed for each of the larger five firms and for every hour in the sample period (January 1st 2009 – December 31st 2011). This no

congestion residual demand curve assumes that the offers of all other suppliers are able to compete with the firm whose residual demand curve is being constructed.

2. The inverse semi-elasticity of this no-congestion residual demand curve is estimated to inform the counterfactual ability the firms would have had in the absence of transmission congestion. Wolak (2012) then calculates the difference between a firm's hourly no-congestion estimate of market power and the firm's hourly realized (i.e. with congestion) estimate of market power. In combination with the econometric analysis, this difference is used to calculate a $/MWh reduction in the offer prices submitted by each of the largest five participants. This allows Wolak (2012) to estimate a counterfactual (i.e. 'no-congestion') offer curve for each of the five largest suppliers for every hour in the sample period.
3. By summing the counterfactual no-congestion offer curves of the largest five suppliers, along with the no-congestion offer curves of the smaller market participants, Wolak (2012) consturucts an aggregate counterfactual (no-congestion) supply curve for every hour in the sample period. This counterfactual supply curve is used with the realized market demand to yield an hourly 'lower bound' estimate of the no-congestion market clearing price, and an 'upper bound' estimate on the benefits of no-congestion that would have accrued to consumers.

Wolak also estimates an 'upper bound' counterfactual market clearing price by constructing an alternative counterfactual aggregate supply function that uses only quantity steps on the individual offer curves that were actually accepted (in other words, generators that were not dispatched at the realized market clearing price are excluded from being dispatched in the counterfactual market equilibrium). This implies that the counterfactual price is equal to the highest offer price with a positive quantity accepted from it in the actual hourly dispatch

process. This process yields a conservative 'lower bound' estimate on the hourly benefits of 'no perceived' congestion because it stipulates the same dispatch of generation units and same amount of congestion as actually occurred.

Using this approach, Wolak (2012) estimates an 'upper bound' estimate of $79,560 per hour for the average hourly benefits of no-congestion that would have accrued to consumers. The lower bound estimate of no perceived congestion gave an average hourly consumer benefit of $3,067. In conclusion, Wolak (2012) argues that these empirical results argue in favor of including competitiveness benefits in transmission planning processes in order to ensure that all transmission expansions with positive net benefits to consumers are undertaken.

While Wolak's analysis is relevant for the current market rules in Alberta, from a broader policy perspective, it is worth noting that the impact of transmission congestion on the ability of generators to exercise market power is largely determined by the rules that govern how the market operates, and in particular how market prices are set, when transmission congestion occurs. At present, the ISO rules governing the Alberta market mean that local transmission constraints can have an important effect on market-clearing prices for the entire Alberta market (i.e. the price effects are not localized). As a consequence of these market rules, the impact of local congestion on the ability of firm's to influence market-wide clearing prices is clear, and therefore, the competitive benefits associated with additional transmission capacity can be large under this market framework. The rules governing the operation of Alberta's electricity market in times of congestion are currently under review with the Alberta Utilities Commission ('AUC').

4.4 The Lerner Index and Offer-Cost Margins

While the theoretical benchmark of perfect competition is of little practical relevance in 'energy only' electricity markets, this benchmark can be used to evaluate the competitiveness of offer behaviour. In a perfectly competitive market, all firms are price-takers and will offer into the wholesale market at marginal cost. Consequently, in a competitive market the clearing price will equal the marginal costs of the generator at the margin. These observations give rise to two related approaches to estimating market power. One approach is to directly compare the offer prices submitted by the generators with an estimate of their marginal costs of production. The second approach is to estimate the Lerner Index by comparing prevailing market prices with the estimated marginal costs of the generator at the margin.

There have been a number of empirical studies comparing offer and cost data to determine the extent to which market power has been exercised in electricity markets. For example, von der Fehr and Harbord (1993), Wolfram (1999) and Wolak and Patrick (1997) all attempt to quantify the price-cost markup for the two major suppliers, National Power and PowerGen in the England and Wales power market.

In an early example, von der Fehr and Harbord (1993) analyzed the offer behaviour of PowerGen and National Power in the England and Wales market from May 1990 to April 1991.[49] The authors estimated marginal costs using published thermal efficiencies and fuel prices. At this time, National Power (with 52% of the market capacity) and PowerGen (with 33%) were the major two suppliers. von der Fehr and Harbord (1993) found that for the first 9 months of the

[49] This was the initial year of the market's deregulation; Britain was the first major government to attempt to fully introduce competition into the wholesale electricity market.

market's operation both firms offered capacity at prices close to their estimated marginal costs. The authors cite low market demand and extensive forward contracts as principal explanations. However, as demand increased during the winter season, the authors note a change in offer behaviour and highlight that PowerGen was increasingly bidding above estimated marginal costs.

Wolfram (1999) obtains a direct measure of the Lerner Index in England and Wales using data on market-clearing prices and direct estimates of marginal costs. These estimates are based upon plant efficiency data and prevailing fuel prices. In addition, Wolfram also uses the New Empirical Industrial Organization approach and regulatory distortions to obtain estimates of the price-cost markup without directly using cost data. The results of these approaches are generally consistent with the direct approach, with all estimates finding price-cost markups in the region of 25%. Wolfram also notes that such markups are much lower than economic models would predict in the context of two large dominant suppliers facing an inelastic market demand. She emphasizes forward contracting, regulatory constraints and the threat of entry as possible reasons for this observation.

These direct approaches are relatively feasible in electricity markets since the prices of fuels such as coal and natural gas are widely published, and the operating characteristics of generation plants are fairly standardized, and consequently relatively well understood. That said, it is important to realize that an accurate measure of the Lerner Index or of offer-cost margins requires a detailed understanding of the marginal costs faced by a variety of producers at every point in time. This is not always straightforward. The marginal costs of generation will vary according to output levels, prevailing weather conditions and should also incorporate start-up

costs where necessary. For Hydro units, the marginal cost is not measured by the costs of production but instead by the opportunity costs of producing power at a specific point in time.

In many deregulated US electricity markets firms must, by law, provide detailed cost information to market monitors on an ongoing basis. This information is used by the market monitors to calculate the offer-cost margin before real-time. When the market is deemed to be structurally uncompetitive and the offer-cost margin is excessive the monitor will mitigate the firm's offer price down to the competitive level. In such markets, firms are compensated for fixed costs and sunk investments in separate capacity markets, where generators are paid for their potential availability.

In these 'markets' the detailed level of cost data available to monitors is also used to track the Lerner Indices of various generators, as well as the Market Lerner Index. The Market Lerner Index is estimated by comparing the marginal costs of the highest-cost generator required to meet prevailing demand with the resulting market price. When undertaking such analysis it is important to consider that prices may exceed the costs of the marginal supplier for reasons other than supplier market power; scarcity events, start-up and shut down costs, and system congestion are all notable examples. Consequently, it is difficult to assert that a large price-cost margin is the result of participant behaviour and not because of estimation errors.

A direct comparison of a firm's marginal costs with the market price is subject to a similar critique, although this measure is misguided on a more fundamental basis. In particular, the firm-level Lerner index fails to recognize that efficient firms will necessarily earn Ricardian rents when higher-cost generation is required to meet prevailing market demand. Therefore, the

firm-level Lerner Index will not distinguish between rents earned through market power and rents earned through economic scarcity and comparative efficiencies.[50]

4.5 Net Revenue Analysis

Net revenues are often used as an overall indicator of generation investment profitability. More specifically, net revenue is the $-amount that remains, after short-run variable costs have been subtracted from gross revenues, to cover total fixed costs.[51] This Net Revenue can then be compared with the revenues required to cover total fixed costs.

Economists and market monitors generally use Net Revenue Analysis to analyze whether the market is providing the correct incentives to attract or deter new investment. The value of Net Revenue Analysis is to analyze whether potential new entrants would earn sufficient revenues to warrant investment, and also to examine whether existing generators are earning sufficient revenues to cover fixed costs.[52] In the long-run the market equilibrium should provide net revenues that are sufficient to cover the all-in costs associated with building additional generation capacity, to the extent that this generation is required and competitive. Note that this equilibrium does not require that existing generation technologies should earn sufficient revenues.

Joskow (2003) uses a form of net revenue analysis to show that the New England energy markets did not provide sufficient scarcity rents to recover the annualized fixed costs of operating a

[50] This same argument refutes the efficacy of using accounting profits to gauge the market power of generators.

[51] The variable, or avoidable, costs included in the absolute net revenue calculations can vary from one analysis to the next. This treatment differential will impact the dollar-value of net revenues but the overall implications, as provided by the percentage contribution of net revenues to fixed costs, will remain consistent.

[52] See Monitoring Analytics (2012) for example

peaking unit during times of market scarcity. Joskow (2003) used this net revenue analysis to highlight that, without structural adjustments, the existing New England markets would not provide the necessary incentives for investment in new generating capacity to maintain the desired reliability levels. More recently, the Brattle Group (2012) undertook a similar analysis of investment incentives and resource adequacy in Texas (ERCOT).

While Net Revenue Analysis can be instructive to ensure that the market signals are consistent with the observed market fundamentals, using Net Revenue Analysis to gauge the market power of incumbent firms is inherently unappealing. Significant Net revenues are not proof of market power. Fundamentally, analyzing net revenues is simply analyzing the prevailing market prices and comparing them to estimated costs. As with the Lerner Index, this method will not distinguish between Ricardian rents earned through scarcity and the exercise of market power.

4.6 Output Gap Analysis

Output gap analysis is used to estimate the amount of capacity that a firm economically withholds from the market. This behavioural analysis is based on the same fundamental premise as the price-costs and Lerner Index measures; in a perfectly competitive market, all firms act as price-takers and supply all output for which the market price is greater than marginal cost. Firms facing a downward sloping residual demand curve have some degree of market power and recognize that profits can be increased by withholding generation in order to raise the market price realized on generation that is sold. With this distinction, the objective of the output gap analysis is to identify generation capacity that would have been supplied by a price-taking firm but was withheld from the market.

The output gap analysis is advanced by Stoft (2002) who argues that the most basic approach to detecting market power is to look for 'missed opportunities'. According to this view, the focus on assessment of market power should be on output and looking for generation capacity that would have been profitable to run at prevailing market prices, but was economically withheld. Using this intuition, economic withholding is measured by estimating an 'output gap', which is defined as the difference between the unit's capacity that is 'economic' at the prevailing market price and the amount that is actually produced by the unit:

$$Output\ Gap_{UT} = Q_{UT}^{COMP} - Q_{UT}^{ACTUAL}$$

Where Q_{UT}^{COMP} is the competitive quantity of unit U at time T and Q_{UT}^{ACTUAL} is the unit's actual supply.

Therefore, a positive value for the output gap is indicative of economic withholding, to the extent that there are no other explanations. Where the output gap is shown to be small relative to the capacity, it may provide some comfort that economic withholding is not a serious problem. However, even when the output gap is shown to be large the margin of error in estimating a number of inputs to this index leaves open to question the significance of any particular result (Twoney el al (2005)).

In order to determine a unit's "competitive quantity" an acute understanding of the unit's variable costs and an estimation of competitive offer price(s) is required. As with the bid-cost margin discussion above, attempting to directly model a firm's competitive behaviour is troublesome, and the previously mentioned criticisms of these estimates apply here:

- In addition to variable costs, such an analysis must take into consideration other relevant costs such as start-up and shut down costs. For example, a competitive generator may optimally withhold its capacity during off-peak hours because if prices spike for short-periods, these price spikes will not be sufficient to cover the start-up and shut-down costs.
- For hydro generation variable costs are close to $0 but the opportunity costs associated with using up the dammed water can be significant if future prices are expected to be high.
- Unit specific cost information is commercially sensitive and maybe difficult to obtain.

Joskow and Kahn (2002) use an output gap analysis to analyze the conduct of generators in the California electricity market during the summer of 2000. The authors avoid many of these issues related to estimating generator costs by examining only hours in which the real-time market prices were well above the costs of peaking gas generators. In particular, the authors only analyze hours when the real-time price was above 17,000 Btu/kWh times the delivered gas price plus 1 lb NOx/MWh times the monthly RECLAIM Trading Credits (RTC) price (a heat rate threshold which covered virtually all steam and most peaking units operating in California, plus a NOx threshold).

The authors analyze different zones of the market (Southern (SP15), Northern (NP15), San Fansico (SF) and Zone at Path 26 (ZP26)) separately and examine the output gap of units likely to be setting prices during the identified high-priced hours. In calculating this output gap, Joskow and Kahn (2002) do not distinguish between the economical and physical withholding of capacity, which is problematic because unexpected forced outages at gas-peaking plants are not

uncommon during hot summer days. Indeed, the authors highlight that three non-strategic factors may explain the output gaps observed:

1. Capacity may be covering Ancillary Service requirements.
2. Capacity may be out of service due to forced outages.
3. North-South transmission constraints may limit the economic dispatch of Southern plants.

To deal with issues 1 and 3, the authors simply subtract total undispatched Ancillary Service demands from the calculated output gap and remove hours in which the North South transmission path was congested. Doing so, the authors yield the following results for June 2000.

Table 7. Mean Level of the Output Gap: June 2000

		Mean Values (MWh)			
Zone	Owner	Output	Capacity	Gap	Undispatched AS
NP15	Duke	1,469	1,485	16	
	Mirant	2,063	2,629	565	
	NP15 Total	**3,532**	**4,114**	**581**	**1,222**
SF	Mirant	206	369	163	
	SF Total	**206**	**369**	**163**	**24**
SP15	AES/Williams	2,735	3,967	1,232	
	Duke	675	717	42	
	Dynegy	1,492	2,834	1,342	
	Reliant	2,492	3,790	1,298	
	SP15 Total	**7,394**	**11,308**	**3,913**	**1,326**
ZP26	Duke	990	1,021	31	
	ZP26 Total	**990**	**1,021**	**31**	**31**

As highlighted, the average observed output gap in SP15 is almost 2,600 MW (after Undispatched AS capacity has been removed) during the 96 events examined. 2,600 MW

represented 23% of the thermal capacity owned by the merchant generators in this zone. Joskow and Kahn (2002) note that this output gap cannot reasonably be explained by forced outages, highlighting that historical outages rates were around 7.5%. In the Northern Zone the calculated output gap is much less, 581MW, and may potentially be explained by the AS requirements.

In conclusion, the authors note that their output gap analysis illustrates the withholding of capacity from the SP15 market in order to increase prices in that market during the summer of 2000, stating that "there is sufficient empirical evidence to suggest that the high observed prices reflect suppliers exercising market power."

The authors also contrast the behaviour of Duke Energy to other generating companies. As shown, the calculated output gap for Duke is significantly smaller than the output gap for other merchant generators on a proportionate basis. The authors explain that Duke reported much lower forced outage rates and had significantly higher production levels relative to other firms. The authors explain this observed difference with economic incentives. In particular, the authors note that Duke had contracted ~90% of its generating capacity at forward prices that were independent of the realized real-time prices. Therefore, Duke did not have the economic incentives to increase market prices by withholding its generation capacity.

4.8 Competitive Market Simulations

Market-level simulations can be used to estimate counterfactual competitive market outcomes and these results can be compared with realized prices to inform whether market power is a significant issue in the market. In this way, the market-level simulation techniques seek to achieve the same type of analysis as the Lerner Index, although the market-level simulations will

consider a broader level of information in order to construct a competitive market supply function whereas the Lerner Index only considers the variable costs of the marginal unit.

The market simulations approach has been extensively applied to the California electricity market in the wake of the state's energy crisis. For example, Borenstein, Bushnell and Wolak (2002) use data on input and output prices, generator variable costs, and actual production quantities to measure the degree to which wholesale electricity prices in California exceeded competitive levels from June 1998 to October 2000. To do this, Borenstein, Bushnell and Wolak (2002) construct a competitive market counterfactual by assuming that each firm in the market acts as a price-taker. These competitive market counterfactuals are then compared with the observed market outcomes.

Using this analysis Borenstein, Bushnell and Wolak (2002) highlight that the market outcomes observed during the lower demand months of the first two years were highly efficient as the market was almost perfectly competitive during these times. On the other hand, during periods of peak demand in the summer months the authors highlight that market prices were observed to be significantly above those predicted by the competitive simulation model. The authors conclude that "market power in California's wholesale market was a significant factor during the summers of 1998, 1999 and 2000."

A principal advantage of using competitive market simulations is that they allow the author to estimate the aggregate effects of market power, as well as the impact of other changes in the prevailing market fundamentals. For example, Borenstein et. al (2002) highlight that California's electricity expenditures increased from $2.04 billion in the summer of 1999 to $8.98 billion in the summer of 2000. Breaking this down, the authors estimate that 21% of this

increase ($1.46 billion) was due to increased production costs, 20% ($1.39 billion) was due to inframarginal (i.e. Ricardian or scarcity) rents that would have occurred in the absence of market power, and 59% of the expenditure increase ($4.09 billion) was due to the exercise of unilateral market power by the larger suppliers.

However, an important disadvantage of using competitive market simulations is they will capture all the inefficiencies present in the market, some of which may not be due to market power. For example, if lower costs generators were held out of production simply because of a faulty ISO dispatch tool, this type of inefficiency would be attributed to the exercise of market power unless it was specifically modeled in the competitive simulation model. Borenstein et al. (2002) concede that the California market still had a number of design flaws during their sample period that may have contributed to the inefficient dispatch and market pricing observed. However, the authors contend that "for the great majority of these, the flaw would have been benign if firms acted as pure price-takers, rather than exploiting these design flaws to affect the market price." The authors also emphasize that their model illustrates the market to be competitive, and efficient, for extended periods of time within the sample period. This, they argue, indicates a lack of systematic inefficiencies associated with the market design.

However, Harvey and Hogan (2001 and 2002) emphasize that market design flaws can be a principal issue when drawing conclusions about firm market power from competitive simulation models:

> "Drawing inferences regarding competition based on comparisons between actual prices and those simulated in these simple models could produce substantial errors. The difference between the actual and simulated prices could arise from the real-world

> constraints omitted from the model in conjunction with purely competitive behavior, or the difference could arise from the exercise of market power by sellers that are able to raise prices because of constraints omitted from the model. One simply cannot tell from these simulations. The error is larger than the effect being estimated." (Harvey and Hogan (2002))

A related issue is that competitive simulation methods necessarily require the author to make a number of simplifying assumptions regarding complicated issues. For example, even if the production capabilities of a generator and its variable costs of production may be accurately observed from historical regulation-era data or from engineering assessments, obtaining a precise estimate of opportunity costs of production is both critical, and is particularly problematic for hydro generation. As noted in Borenstein et al. (2002), even if one can observe a firm's variable costs of production, it is important to identify a firms opportunity costs in order to distinguish between profits resulting from Ricardian rents and those obtained through the abuse of market power.

Harvey and Hogan (2001) undertake a detailed analysis of the market design issues in California and of the underlying assumptions made by competitive simulation models of the market. In conclusion, Harvey and Hogan (2001) highlight that their sensitivity analysis of the assumptions underlying the competitive simulations models renders the results of these models useless in terms of its ability to detect and quantify the effects of market power:

> "…[A]nother series of sensitivity analyses have concluded that the simplifying assumptions of the simulation models and the other analyses with publicly available data were enough to introduce errors as large as the effect that was to be estimated. In other

words, the publicly available data were not up to the task of detecting a substantial exercise of market power."

Clearly, the simulation of competitive market outcomes in electricity markets is not straightforward. To obtain an accurate competitive counterfactual would require the researcher to account for a myriad of factors including; unit heat rates, fuel prices and opportunity costs; start-up and shut down costs; forced and scheduled outages; unit minimum load requirements; ancillary service requirements; and structural or market design issues.

As a consequence, the ability of simulation models to accurately estimate a competitive counterfactual market will depend upon the accuracy of the assumptions underlying the model, and the ability of the model to reflect the market's design and operation. A simplified model with poor underlying assumptions will provide poor counterfactual estimates, resulting in misleading conclusions about the extent of competition. In addition, if the simulation method is unable to accurately model the functioning of the market this may lead to results which overestimate the impact of unilateral market power on market outcomes.

Chapter 5: Measures of Market Power for the Alberta Wholesale Electricity Market

This section develops two measures of structural market power that are to be analyzed in the thesis. The first measure of market power constructs a firm's realized residual demand function and uses the estimated semi-elasticity of this function to make inferences about the firm's ability to influence the prevailing market price. The second measure of market power developed is a variant on the Residual Supplier Index ("RSI"). Fundamentally, RSI measures analyze the extent to which a particular firm is pivotal in the market. The approach developed here, labeled the 'Adjusted RSI', accounts for the fact that a large amount of capacity under the offer control of generators in Alberta is 'must-run' capacity that is not readily withheld. For the two measures of market power, this section discusses the theoretical motivations behind the approach and also illustrates how the metrics are constructed using publicly available AESO data.

5.1 Residual Demand Analysis

5.1.1 Residual Demand Analysis: Economic Underpinnings

The theoretical justification for analyzing the elasticity of a firm's residual demand function is drawn from the economic theory of profit maximization. Economic theory highlights that a generator will maximize profits by producing output such that the marginal revenue earned on an additional unit equals the marginal cost of producing that unit. This theory of profit maximization can readily be applied to a firm that faces a residual demand function $RD(p)$. A firm's residual demand is the market demand that is 'left-over' given the offer functions submitted by competing firms, and the term 'residual demand' comes from the idea that a particular generator can supply only those MW not supplied by its competitors:

$$RD(p) = QD(p) - SO(p)$$

Where $QD(p)$ is market demand and $SO(p)$ is the supply of other firms.

A firm's residual demand is a negative function of price. As prices rise, market demand is potentially reduced and the supply of other firms will increase. Both of these serve to decrease the firm's residual demand. Conversely, as the market price falls other suppliers will reduce their output and market demand will tend to rise, causing a firm's residual demand to increase.

A generator with market power will maximize profits by recognizing that its output decision will influence the market price. By supplying less electricity to the market, the generator can increase the market price and realize a higher price on the power that is sold. In other words, a generator with market power will maximize profits by recognizing that it has two components to its marginal revenue. Firstly, through increasing its supply by a single unit, the firm obtains an increase in revenues equal to the resulting market price (p). Secondly, by selling this additional unit, a generator with market power will lower the market price and so the firm suffers a loss on all generation dispatched. The extent to which the firm will lower the market price depends upon the slope of the firm's inverse residual demand function ($\frac{\partial p}{\partial RD}$).

For a firm facing a steep inverse residual demand function $\frac{\partial p}{\partial RD}$ is a large negative number; by increasing output the firm will meaningfully lower the resulting market price. Since the firm

incurs this price loss on all units sold (RD), this loss in revenue is equal to $\frac{\partial p}{\partial DR} RD$.[53] Summing these two components, the generator's marginal revenue is given by:

$$MR = p + \frac{\partial p}{\partial RD} RD$$

The firm maximizes profits by producing the quantity of output for which marginal revenue equals marginal cost:

$$p + \frac{\partial p}{\partial RD} RD = MC$$

Subtracting MC and $\left(\frac{\partial p}{\partial DR} RD\right)$ from both sides and dividing through by p allows this condition to be written as follows:

$$\frac{(p - MC)}{p} = -\frac{\partial p}{\partial RD} \frac{RD}{p}$$

The term on the right hand side is the inverse elasticity of the firm's residual demand function $\left(\frac{1}{|\varepsilon_{RD}|}\right)$. The elasticity of a firm's residual demand (ε_{RD}) quantifies the percentage fall (rise) in the firm's residual demand that is associated with a 1% increase (decrease) in the market price. The residual demand function is relatively inelastic if the function is steep, and small changes in quantity have a large impact on the market price. This inelasticity is reflected by a high value of $\frac{1}{|\varepsilon_{RD}|}$, while lower values reflect a relatively elastic residual demand.

[53] Note the $\frac{\partial p}{\partial RD}$ figure is negative because the residual demand function is downward sloping. For a firm with no market power $\frac{\partial p}{\partial RD}$ is 0, indicating that the firm's output decision has no impact on the market price.

$$\frac{(p - MC)}{p} = \frac{1}{|\varepsilon_{RD}|}$$

The left-hand side of the above equation is the Lerner Index. This index shows the extent to which the market price exceeds marginal costs. As shown by the above equality, a profit maximizing generator facing an inelastic residual demand function will optimally set price above its marginal costs by reducing supply below the competitive level. Conversely, a firm facing a relatively elastic residual demand curve has little ability to move price and will optimally offer its generation at a price close to marginal cost. For example, a firm with no market power will face a flat residual demand curve ($\frac{\partial p}{\partial RD} = 0$) and will optimally sell any output for which the market price is above the marginal costs.

Since a generator's residual demand is a function of market demand and the supply of other firms, the elasticity of the firm's residual demand will depend upon the elasticity of market demand and the ability of competing generators to respond to changes in price. In this way, the profit maximization condition highlights that the market power of a firm facing a downward sloping residual demand function will decrease (increase) as the ability of consumers to undertake demand-side or supply-side substitution rises (falls).

Demand-side substitution refers to the ability of consumers to substitute away from the underlying product to different goods. Since electricity is a homogeneous good, demand-side substitution here refers to the ability of consumers to reduce their energy consumption as prices rise, to find alternative forms of energy (switching from electrical to gas-fired heating for example) or to use electrical appliances which are more efficient. Demand side substitution is characterized by the elasticity of the market demand function. If market demand is relatively

inelastic this reflects the inability or unwillingness of consumers to substitute to other goods. The short-run elasticity of market demand is determined by the amount of demand which responds to real-time prices. As discussed in section 1.5.1, the demand for power is almost perfectly inelastic in the short-run since there are no short-run substitutes for electrical power and because many consumers do not face the prevailing spot price. In the Alberta market there is ~200 MW of demand which is price-responsive (see section 3.3.1). At peak times, this accounts for approximately 2% of total market demand. Consequently, a rise in the wholesale price has relatively little impact upon the prevailing demand for electricity.

The principal factor limiting the market power of generators in the Alberta wholesale power market is the potential for consumers to substitute to different suppliers of electricity. The ability of rival generators to increase their supply in the event of a price rise can be analyzed by aggregating their willingness-to-supply functions. The elasticity of this 'supply-of-other-firms' function will illustrate the extent to which other suppliers can compete with a quantity change undertaken by a particular firm. As the supply of other firms becomes increasingly elastic the firm has less market power since other firms are able to increase (decrease) their supply in the event of a price rise (fall). In contrast, as other generators become less able to change their supply as prices vary, a firm might be able to affect the market price quite substantially with a relatively small amount its generation.

In summary, the elasticity of a firm's residual demand function is an important consideration for any profit-maximizing supplier. In the Alberta electricity market, the elasticity of a firm's residual demand function depends principally upon the elasticity of the supply-of-other-firms. As other suppliers become less able to vary their generation levels in response to changes in

price, a firm's residual demand function will become less elastic, indicating that it has a higher level of market power.

5.1.2 Residual Demand Analysis: Empirical Estimation

The Residual Demand approach can be readily applied to the Alberta electricity market because the data on real-time market demand and offers is publicly available on the AESO's website. For each hour a firm's residual demand can be calculated by subtracting all of the offers submitted into the Energy Market by rival market participants from the total demand in the Energy Market:

$$RD_{1h}(p) = QD_h - SO_{1h}(p)$$

Where $RD_1(p)$ is Firm 1's residual remand at price p, QD is the realized Energy Market demand, and $SO_1(p)$ is the supply of all other firms at price p; the h subscript simply shows that the measures are hourly.

As an example, the derivation of TransCanada's residual demand[54] function for Hour Ending 11 on August 3rd 2011 is illustrated diagrammatically by figures 15 and 16. Figure 15 shows an illustration of the hourly Energy Market Merit Order (labeled as 'Market Supply') and the total energy dispatched from the Energy Market (labeled 'Total Demand'). As shown, market demand is assumed to be insensitive to price changes and hence is a vertical line.

The Supply of Other Firms function illustrates the offers submitted by all of TransCanada's competitors in this particular hour. Hence, the difference between market supply and the supply

[54] Strictly speaking the function is the inverse residual demand function because it shows price as a function of the firm's output. For simplicity the 'residual demand function' used here refers to the inverse.

of other firms is the offer curve of the firm under consideration. As shown, TransCanada's residual demand function does not depend directly on its own offer strategy, but it is a function of the prevailing market demand and the offer strategies of competing firms. In addition, the figures illustrate that the slope of a firm's residual demand will depend directly upon the slope of the supply-of-other-firms function.

Figure 15: Energy Market Fundamentals and the Construction of a Firm's Residual Demand Curve

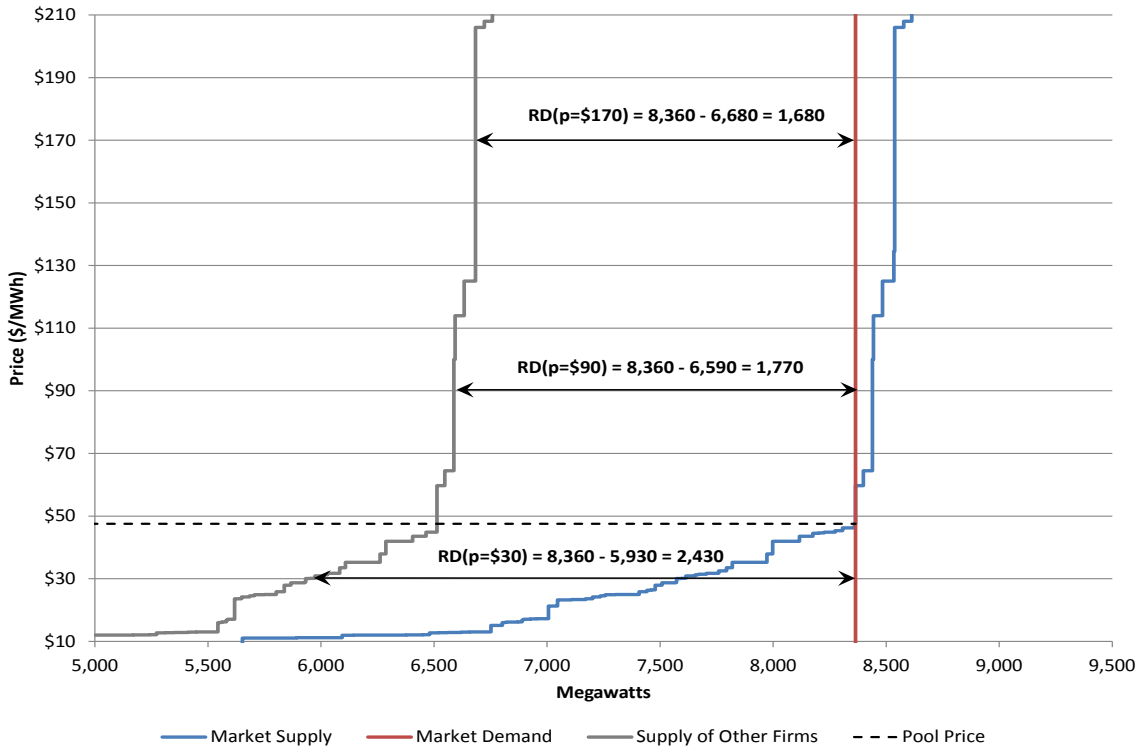
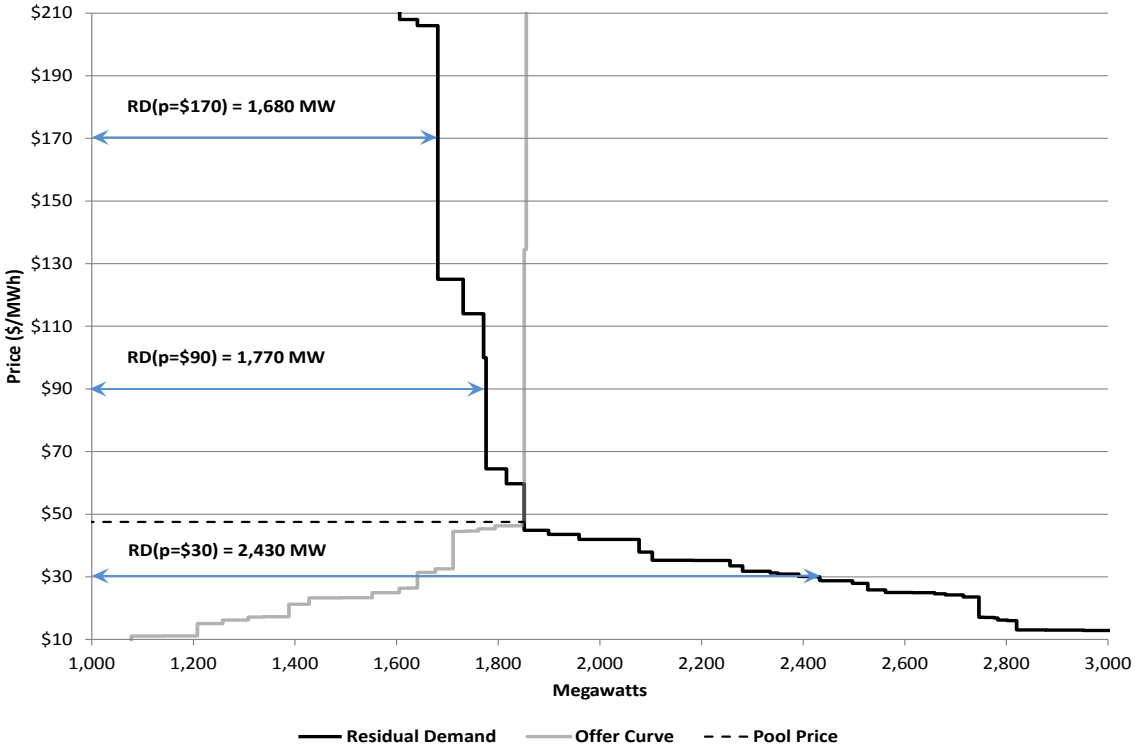


Figure 16: The Residual Demand Function and the Offer Curve



In the example illustrated by figures 15 and 16, the residual demand curve is shown to be fairly steep above the market clearing price, as the presence of competing generation was relatively sparse in this price region. The steep slope of the firm's residual demand function above the market clearing price illustrates that TransCanada could have increased the price quite substantially by reducing its supply in this example. That is, the slope of the residual demand function above the market price is informative as to the potential ability that the firm had to increase the market price in this hour. In this example, there were only 250 MW offered by competing firms between the realized price and the 'shelf' just below $210. Therefore, by withholding 250 MW (or ~14%) of its supply, the firm could have increased price by over 300% (from <$50 to >$200).

The slope of a firm's residual demand curve below the market clearing price is also informative. In particular, the slope of the residual demand curve below the market price indicates the ability the generator had to increase the market price to the realized level. In the above example, the slope of the firm's residual demand function below the market equilibrium is relatively flat, implying that the firm had little ability to increase price to the level realized.

Since both the areas above and below the market clearing price are relevant to measuring the ability a firm had to move price, the thesis considers a metric that estimates the residual demand slope around the market-clearing price. The steeper the slope, the less competition was faced from other generators at the margin, implying greater market power. In practical terms, the estimated slope provides a dollar-estimate of a firm's ability to influence the market price with 1MW of energy being withheld.

To construct a firm's ex-post residual demand function this thesis uses data that is publicly available from the AESO's website. In particular, the thesis uses historical data from the 'Merit Order Snapshot - Energy'[55] report which provides a snapshot of the Alberta energy market mid-way through a given hour. The residual demand function faced by a particular supplier j in hour h is given by the following equation:

$$RD_{jh}(p) = QD_h - SO_{jh}(p)$$

Total demand (QD) in the Energy Market is found by totaling all the offered capacity (including imports) that is dispatched. There is no need to adjust this measure for exported energy because

[55] This report is available with a 60 day lag from the AESO's website.

this energy is already included - higher exports will result in more domestic capacity being dispatched.

Note that the residual demand function does not account for price-responsive loads and effectively assumes that the demand curve is perfectly inelastic. In practice, the Alberta market has ~200 MW of price-responsive loads that can reduce the ability of generators to influence market price. Analysis done by the AESO (2009b) is corroborated by figure 7 in section 3.1, and indicates that these loads tend to be most responsive around the price range of $80 - $300. The residual demand analysis could potentially incorporate price-responsive loads, however, this refinement has not been made since the relative size of price-responsive loads is small, and accurately estimating the market demand function is not straightforward.

The Supply of Other firms function (SO_j) is an upward sloping step function which indicates the aggregate willingness-to-supply of all other market participants at a particular price. To calculate this function requires specifying which participant is responsible for submitting each offer block. In Alberta, offer control is complicated by the PPAs and by assets which are jointly controlled by multiple participants (section 3.4). For the residual demand analysis, offer control for PPA assets is assigned completely to the PPA Buyer and energy blocks from assets which are jointly controlled (KH3 and GN3) are split evenly between the two participants (TransAlta and Capital Power).

Having clarified which blocks are controlled by rival generators, the Supply of Other firms function faced by a participant is derived from the Dispatched MW and Available MW columns in the 'Merit Order Snapshot - Energy' report. For energy blocks that are dispatched, the Supply

of Others function is constructed using the Dispatched MW column. For offer blocks that are above the clearing price, the calculation uses the declared Available MW.

Constructing the Supply of Other Firms function also requires consideration of the Transmission Must Run ('TMR') and Dispatch Down Service ('DDS') markets. In particular, the thesis accounts for the fact that crossing the TMR reference price will cause rival generators to increase or decrease their supply through the DDS market when TMR generation is required.[56] For instance, suppose that 100 MW of TMR is being used by the AESO in a given hour. Also suppose the TMR reference price is $30. If the market clears below the TMR reference price, the AESO will offset its use of TMR by dispatching down 100 MW of generation through the DDS market. Suppose that 60 MW of this DDS would be obtained by other firms reducing their supply, whilst the remaining 40 MW of reductions would be obtained from the firm being analyzed. Under this scenario, if the market price were to rise above the TMR reference price at $30, the AESO would cease using the DDS market, and so the supply of other firms would be 60 MW higher when the market price is above the TMR reference price. Therefore, in this case, the supply of other firms function has a 60 MW block offered at the TMR reference price.

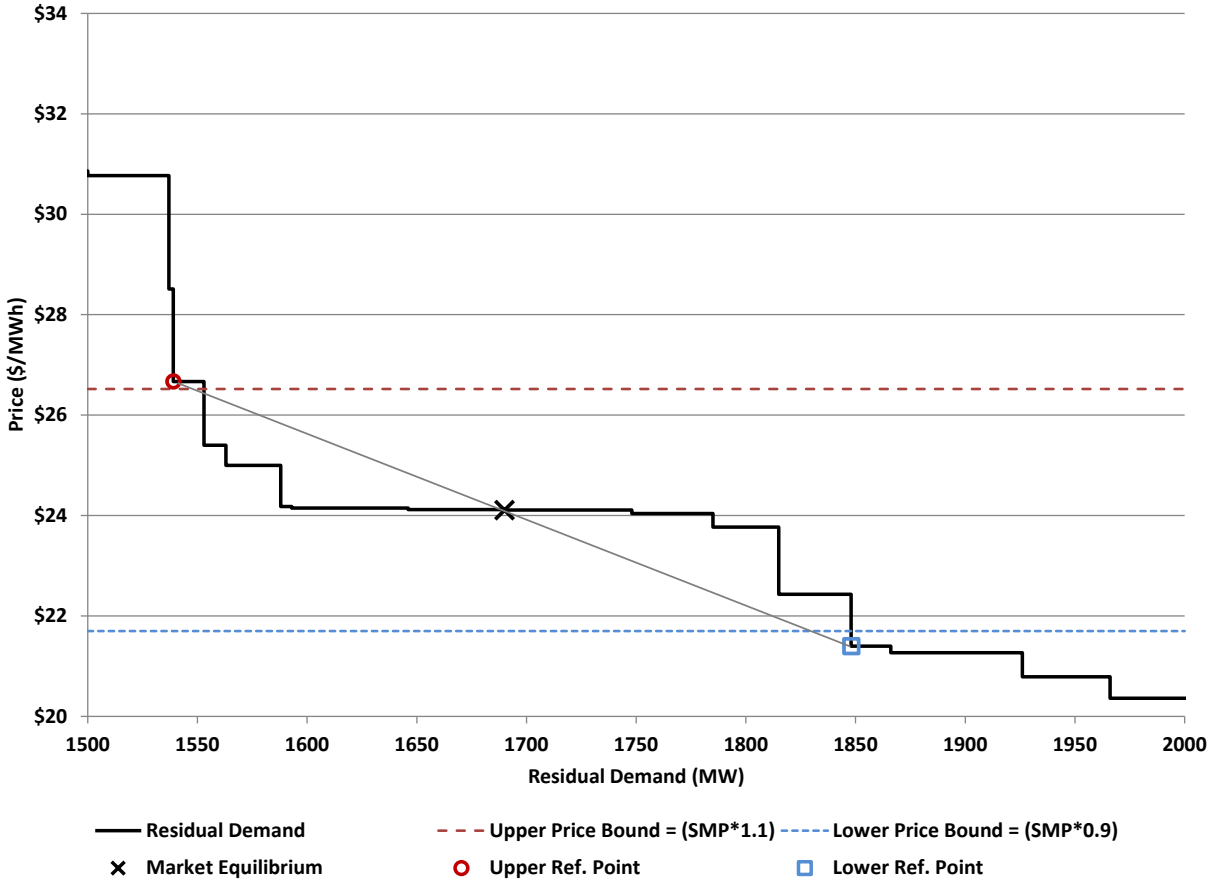
Once the Supply of Other Firms function is derived, it is subtracted from the realized market demand function to construct the firm's estimated residual demand function. Because a generator's residual demand function is a step function, approximating its slope requires a first-difference approach. To do this, the thesis adopts the approach taken by Wolak and McRae (2012) who analyze the market power of generators in the New Zealand electricity market. This method begins by constructing a 10% 'price window' around the market clearing price (System

[56] See section 2.5.2 for an outline of TMR and DDS.

Marginal Price ('SMP')) - the upper bound is calculated as (1.1*SMP) and the lower bound as (0.9*SMP). Figure 17 illustrates an example of this 10% price window.

The method then proceeds to find the two steps on the firm's residual demand function that are just outside the constructed price window. The reasoning here is that the hypothetical output change should cause the equilibrium price to change by at least ten percent in order to get a good representation of the residual demand function around the market equilibrium.

Figure 17: Example 1 - Estimating the Slope of a firm's Residual Demand function



In the example illustrated by Figure 17, the step just above the upper price bound is a 14 MW block offered by a rival generator at $26.67. At a price of $26.67 this 14 MW is dispatched and the firm's residual demand is 1,540 MW (highlighted by the red circle in the top left of the

figure). At the lower bound, the initial step outside the lower price window is an 18 MW block offered by a competitor at $21.40 (highlighted by the blue square in the bottom right of the figure). At this lower reference price the firm's residual demand is 1,850 MW.

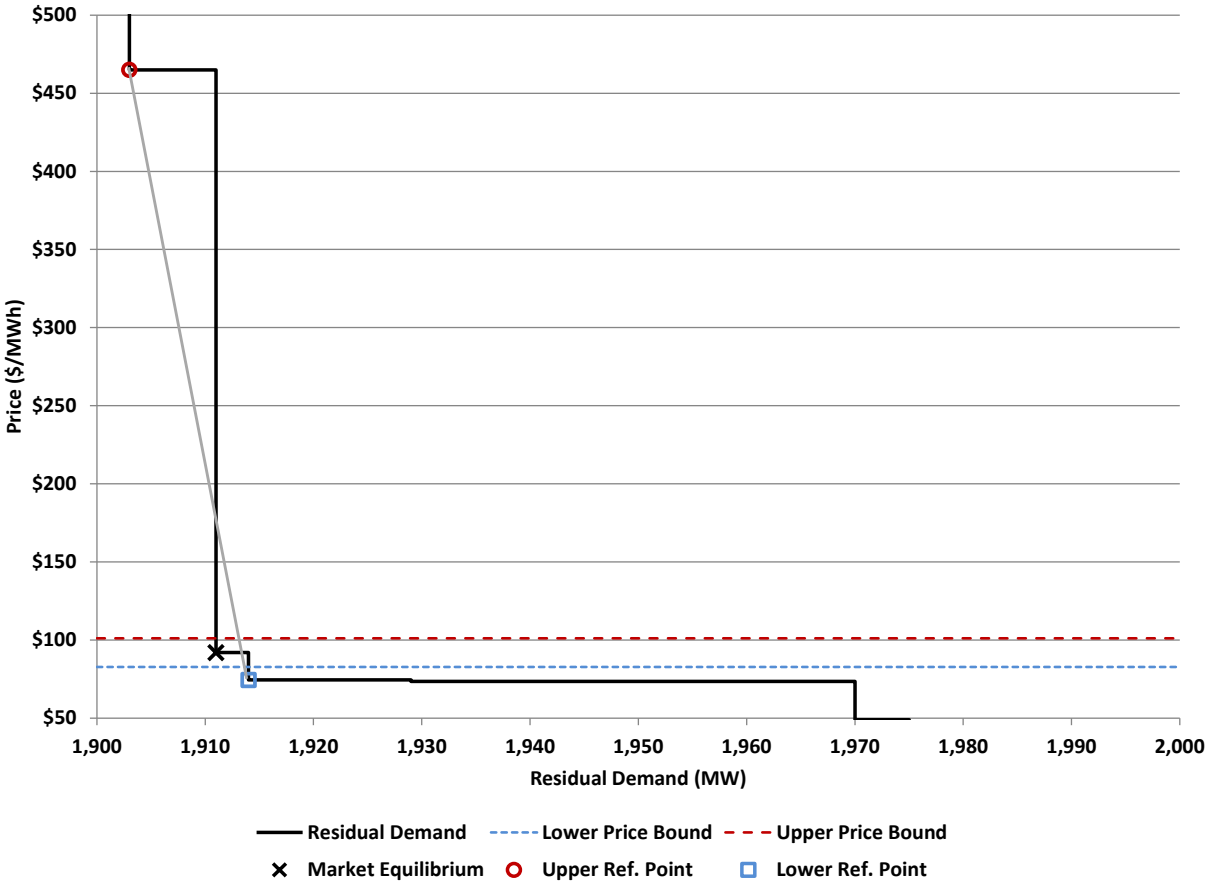
The slope of the residual demand function is then estimated by calculating the slope of the linear function between these two reference points. In the above example, this linear function is highlighted by the grey line. Hence, the slope of the firm's residual demand around the market clearing price (RD'(p*)) is calculated here as:

$$RD'(p^*) = \left|\frac{(26.67 - 21.40)}{(1{,}539 - 1{,}850)}\right| = \$0.017/\text{MW}$$

The resulting low value indicates that the firm's residual demand function was relatively flat around the SMP. The implication is that the market was relatively competitive in this hour and the firm had little ability to influence the market price.

As a contrasting example, figure 18 illustrates an instance where the residual demand function is estimated to be relatively steep. In this example the market cleared at $92 and, because of the huge vertical step above this equilibrium, the upper price point is over $460. Relative to its market clearing quantity, the firm's residual demand falls by only 8 MW from this hypothetical price increase. Beneath the SMP, the lower reference price is $74.50, at which point the firm's residual demand is 1,914 MW. Calculating the slope of the line between the two reference points yields a slope estimate of $35.5/MW, illustrating that at this point in time the firm had a notable ability to influence the market price with a small amount of its generation.

Figure 18: Example 2 – Estimating the Slope of a firm's Residual Demand function



While the slope of a firm's residual demand function is informative, it is also important to account for the prevailing size of the firm under consideration. All else equal, a firm with a greater amount of dispatched power in the real-time Energy Market will have a greater ability to profit from an increase in price.[57] To account for this, the slope of a generator's residual demand function is weighted by the firm's residual demand in the prevailing market equilibrium (i.e. the firm's dispatched generation). Dividing the resulting figure by 100 provides an estimate of the semi-elasticity of a firm's inverse residual demand function (denoted by η). In practical terms,

[57] The profitability of influencing market prices will depend upon an array of factors, including the firm's energy market sales. As discussed in section 5.3.1, to accurately consider the profitability of exercising market power requires consideration of private financial, physical and bilateral contracts which are not publicly available.

this metric provides a dollar-estimate of the price increase the firm could obtain by withholding 1% of its output.

Continuing with the two examples discussed above, in the first example the slope calculated was $0.017/MW. In this example, the firm dispatched 1,690 MW in the market equilibrium. Therefore, the firm's semi-elasticity is calculated as ((1690 * 0.017) / 100) = $0.29; so the firm's ability to influence market prices with 1% of its dispatched generation was limited.

In the second example, the firm's residual demand function was steep and the slope estimated was $35.5/MW. At the market equilibrium the generator dispatched 1,912 MW. The calculated semi-elasticity is ((1912 * 35.5) / 100) = $679. Therefore, the residual demand approach highlights that the firm had a significant ability to affect the market clearing price with a small amount of its output in this example.

5.2 The Adjusted RSI

5.2.1 RSI Measures: Economic Underpinnings

Residual Supplier Indexes make use of aggregated supply and demand fundamentals to measure the extent to which a particular supplier is pivotal. A supplier is defined as pivotal if the realized market demand exceeds the capacity available to competing suppliers. In other words, if a pivotal supplier physically withheld its entire generation capacity, market demand would exceed supply, and the market would not clear. In the context of Alberta's 'Must Offer' rule, this notion of withholding output is more properly thought of as a firm pricing all available capacity at the offer cap of $999.99. By taking such unilateral actions, a pivotal supplier could ensure that it is setting the market price at $999.99 (MSA Q4 Report 2010). Residual Supplier Index (RSI) measures are useful in homogeneous goods markets, such as electricity, where demand-side

substitution is limited. The overriding intuition is that if consumers cannot substitute to other suppliers capable of making up all, or most, of a producer's output reduction, a producer of a homogeneous good will have market power (Church and Ware (2000)).

The basic principles underlying RSI measures can be explained using the following equation:

$$RSI_{jh} = \frac{(Total\ Market\ Supply_h - Supply\ Controlled\ by\ firm\ j_h)}{Market\ Demand_h}$$

Where RSI is the Residual Supplier Index for firm j in hour h.

The RSI metric will decrease as total demand rises relative to the capacity controlled by other suppliers, so a lower RSI highlights that rival firms are able to supply less of the realized market demand. Therefore, a lower value of the RSI is indicative of greater market power. The economic justification for using the RSI as a measure of market power is that the ability of a firm to exercise unilateral market power will depend critically upon the extent of supply-side substitution that a firm faces. Therefore, as the ability of other suppliers to respond to price changes falls, the firm is shown to have greater market power.

Clearly the extent of supply side substitution faced by a firm will tend to decrease as the total supply controlled by other firms falls. Simply put, a large participant that controls 50% of the market capacity in a given hour is likely to face less supply-side substitution than a firm controlling 2% of the capacity. In addition, the extent of supply-side substitution faced by generators will also tend to fall as demand rises. During times of peak demand, rival firms are likely to be operating their generators at higher levels, closer to their units' capacity, so their ability to moderate price rises by increasing supply will tend to fall as demand increases.

In terms of its Residual Demand function, a supplier is shown to be pivotal if the firm's residual demand is positive for all possible prices:

$$DR_j(p = 999.99) = \left(QD - SO_j(p = 999.99)\right) > 0$$

To illustrate this, Figure 19 shows ENMAX's residual demand during an on-peak hour of May 2010. In this example, the total amount of energy dispatched in the Energy Market was 7,630 MW and the market cleared at $730. The total amount of capacity declared as available in this hour was 7,760 MW, with ENMAX offering 1,860 MW.

As highlighted by the Figure, the supply of all other firms reaches its capacity well before system demand is met, as ENMAX's residual demand was substantial even at the price cap. Therefore, the market was heavily dependent upon ENMAX's energy in this hour, and if ENMAX had been willing to sell only 1,730MW, the firm could have ensured the market price reached the cap by offering $(1860 - 1730) = 130$ MW of its capacity at a price of $999.99.

As a contrasting example, Figure 20 shows the residual demand curve faced by ENMAX during an off-peak hour of May 2010. In this example, the market cleared at a price of $8.09 as under 6,000 MW of energy was dispatched from the Energy Market. In this example, other firms offered almost 7,400 MW of capacity into the Energy Market, and ENMAX was far from a pivotal supplier here. In particular, even if ENMAX's generation had been completely absent from the market, other firms supplied 1,400 MW of capacity above that required to meet demand.

Figure 19: Example 1 - A firm's Residual Demand function shows the extent to which the firm is pivotal

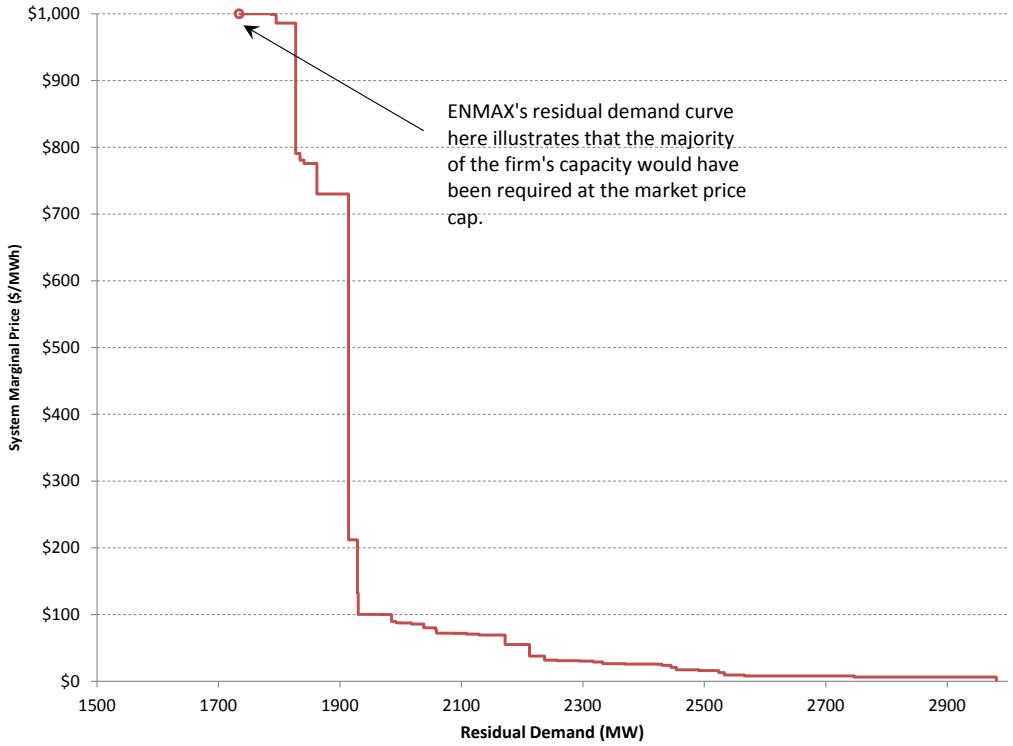
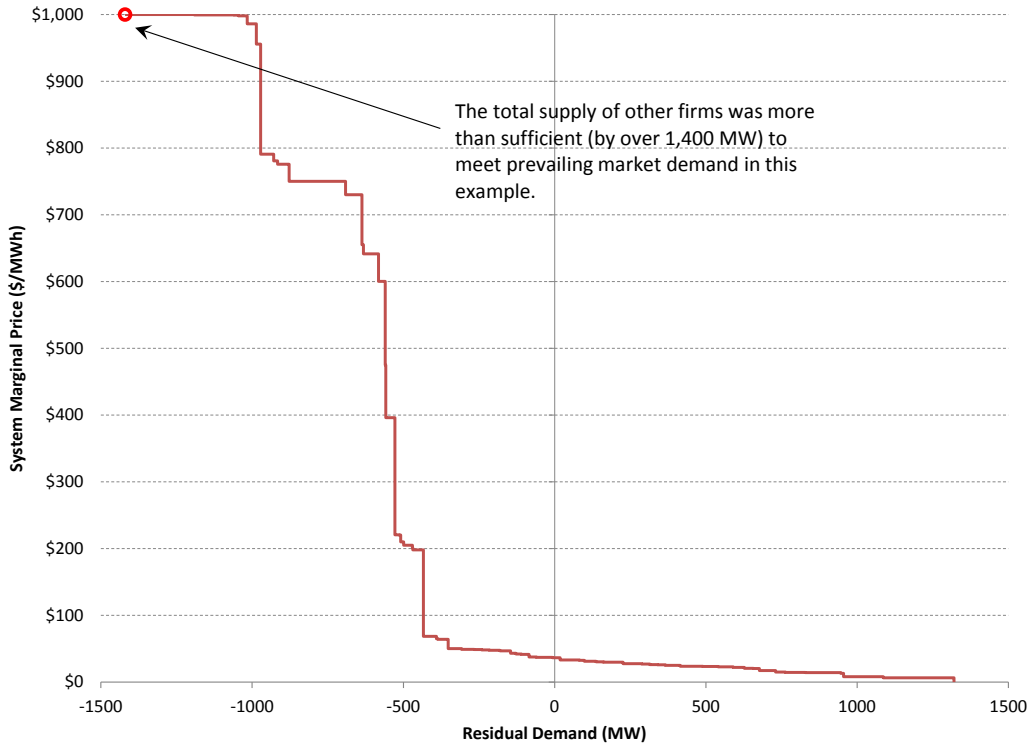


Figure 20: Example 2 – A firm's Residual Demand function shows the extent to which the firm is pivotal

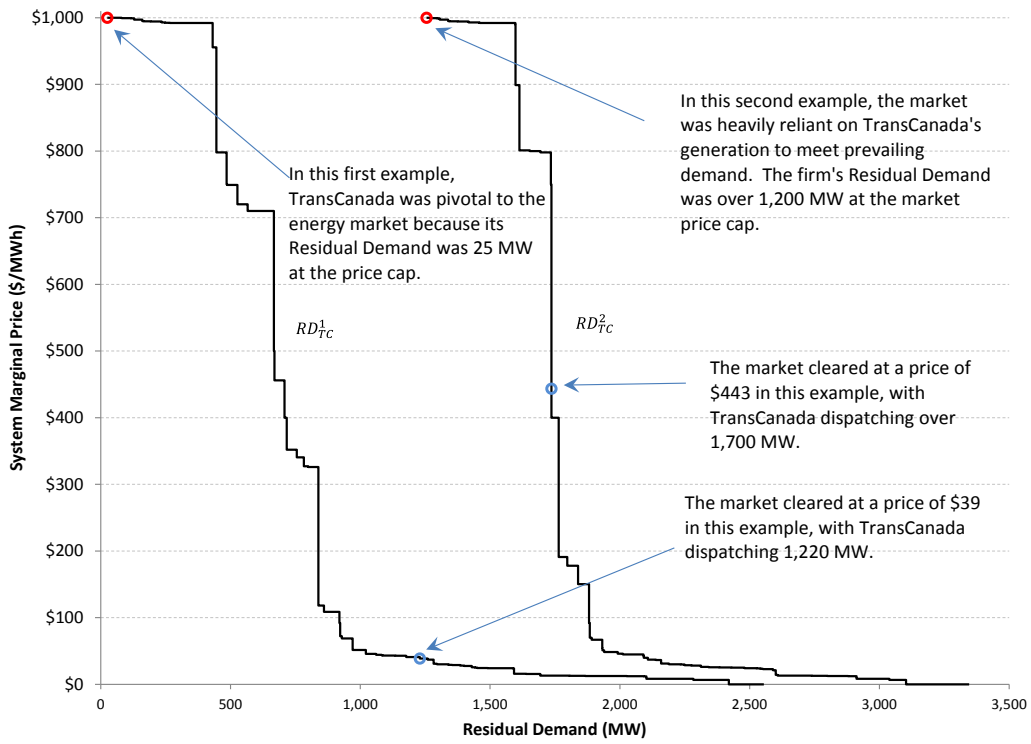


As discussed in the Literature Review (section 4.2), many authors make use of a Pivotal Supplier Index, with the PSI being a binary variable which indicates whether a supplier is pivotal. However, this simple binary analysis is not suitable for the Alberta market because:

- A binary variable does not illustrate the *extent* to which the supplier is pivotal, and;
- The larger firms in Alberta normally have a significant amount of generation that is 'must-run' or otherwise meaningfully constrained.

To see the importance of these issues, it is useful to compare and contrast two examples in which a supplier is shown to be pivotal using the PSI. Two such examples are illustrated by the residual demand functions shown in Figure 21.

Figure 21: Two Residual Demand functions - the firm is shown to be a pivotal supplier in both cases



The first example, illustrated by RD_{TC}^{1}, shows the residual demand curve faced by TransCanada during an on peak hour of April 2011. At the snapshot of this hour, the market dispatched a total of 7,320 MW and the market cleared at a price of $39. In this hour a total of 8,820 MW of capacity was offered into the energy market with TransCanada offering a total of 1,520 MW. Therefore, TransCanada was a pivotal supplier at this snapshot in time, as the capacity of other suppliers was 20MW short of meeting demand.

Using the PSI analysis would indicate that TransCanada was pivotal in this example, thus indicating the firm had structural market power. However, the resulting '1' fails to illustrate that the firm's residual demand at the price cap is only 25 MW, so the firm is only marginally pivotal. To take the market price to $999.99 here TransCanada would have had to economically withhold 1,500 MW of capacity.

In addition to being highly unprofitable from the perspective of short-term revenues, this offer strategy would have been significantly expensive from an operational standpoint as TransCanada would have had to shut down three coal facilities and ceased industrial operations at a number of its cogeneration units. Such actions would be highly costly because coal-fired generators are expensive to shut down and restart, and TransCanada has contractual obligations to supply power and steam to the on-site hosts at many of its cogeneration sites. To prevent such expenses from occurring, a large amount of TransCanada's capacity is offered into the merit order at $0. In the example being discussed here, 855 MW of TransCanada's capacity was offered into the energy market at $0.

The second residual demand function drawn in Figure 21 shows the residual demand function faced by TransCanada during another on-peak hour of April 2011. In this example, the market

was relatively tight as over 90% of the 8,100 MW available in the Energy Market was dispatched, and price cleared at $443. TransCanada offered over 1,900 MW into the Energy Market and so the firm's supply was crucial to ensuring that the market demand was met. As illustrated in Figure 21, TransCanada's residual demand at the price cap is some 1,260 MW. Therefore, by offering $(1900 - 1260) = 640\text{MW}$ of its capacity at the price cap, TransCanada could have ensured the price cleared at this level.

Clearly, there is an important difference between the two examples illustrated in Figure 21. In the first example TransCanada would have had to offer 99% of its capacity at $999.99 to ensure the market price cleared at the cap. In the second example, 34% of TransCanada's capacity was required to have the same effect. Therefore, a principal issue with using the PSI is that this metric does not differentiate between two such contrasting cases.

Applying the generic RSI method to these two examples does show an important difference between the two cases. In the first case, the firm's RSI is calculated as 0.9965, indicating that the firm is only slightly pivotal. For the second case, the RSI metric is considerably lower at 0.8339, indicating that TransCanada's generation is crucial to ensure that system demand is met at this time.

In this way, using the 'generic' RSI is a refinement over a simple binary variable because the RSI metric indicates the extent to which a firm is pivotal. This refinement is an important one in the context of the Alberta market where the larger firms are frequently pivotal to the Energy Market, but are often limited in their ability to influence market outcomes. To illustrate the extent of this issue, using the PSI would indicate that TransCanada was pivotal to the Energy

Market in over 80% of the hours during 2011. To put this result into context, the median pool price in 2011 was $30.

5.2.2 The Importance of 'Must-Run' Generation in Alberta

A principal issue with applying the generic RSI approach to the Alberta market is that the metric does not account for the flexibility of the capacity under a firm's offer control - i.e., the extent to which the capacity can feasibly be offered at a particular price in order to influence market outcomes. This is an important consideration in the Alberta market because a notable amount of capacity is must-run power which is not realistically 'dispatchable' in the short-run:[58]

Coal fired generation is a large part of the Alberta fuel mix and the four largest generating companies in Alberta have a significant amount of coal capacity under their offer control. All of the coal fired generators in the province have a Minimum Stable Generation ("MSG") and it is operationally unsafe to run the units below this level. This MSG can vary because of operational conditions or procedures taking place at the plant. While firms can choose not to run these units in the short-term, there are significant costs to 'cycling' coal-fired units, and so the MSG is typically offered at $0 to avoid start-up and shut-down costs.

Co-generation facilities in Alberta also offer a significant portion of their energy into the market at $0. At these sites, this 'must-run' power is either consumed directly on-site or is dispatched onto the grid as a bi-product of the primary on-site operation (steam requirements for SAG-D oil production is a typical example). Either way, the requirements of the primary industrial process

[58] It should be noted that while these must-run megawatts may not increase the firm's ability to exercise market power, they may well impact the incentives of a firm to exercise market power. A large number of must-run megawatts exposed to the hourly pool price will increase the firm's incentives to raise the pool price, although this position maybe offset by selling forward fixed-price financial contracts (see section 5.3).

will normally limit the practical control that a firm has to vary a cogeneration unit's electrical output.

Hydro generation units will often offer a portion of their generation into the energy market at $0. At the larger hydro facilities these $0 offers reflect a limited storage capacity or environmental restrictions on the flow of water. As well, some of the province's smaller hydro facilities are "run-of-the-river" units with little to no storage capacity. These units can either run the river flows through the turbines and generate power or allow the river to spill through the dam.

Wind, Imports and Exports must all act as price takers under the current ISO Rules. Wind generation is not offered into Energy Market at all but simply generates and serves to reduce demand realized in the Energy Market. On the interties, any imports flowing into Alberta are offered at $0, ensuring they act as price-takers. Likewise, exports from Alberta cannot be bid into the market but will simply pay the Alberta pool price for the power. It is useful to view imports and exports of power as financial contracts that net out to determine the flow of power from one jurisdiction to another. For instance, if there are 1,000 MW of imports into Alberta and 400 MW of exports, the net flow of power will be 600 MW coming into Alberta. Therefore, the ability of a firm to influence market prices through imports and exports should be limited by the actions of competing firms seeking to profit from arbitrage opportunities.[59]

[59] For example suppose prices in Alberta are expected to be $200 above those clearing in California, so the profitable arbitrage opportunity is to buy power from California and sell it into Alberta. Also suppose that only 600 MW of power can be imported because this is the capacity of the transmission lines. Now suppose that a company in Alberta tries to exercise market power by exporting 100 MW from Alberta into California, against the arbitrage opportunity, to raise prices in Alberta. This 100 MW of exports does not prevent 600 MW of power from flowing into Alberta, but instead the 100 MW of exports means that 700 MW of imports is now feasible. In this sense,

It is clear then that a large amount of capacity in the Alberta market is 'must-run' generation which, for one reason or another, is offered into the market at $0. Including such must-run obligations in the RSI metrics will yield a misguided estimate of a firm's ability to exercise unilateral market power. Including a firm's must-run capacity as under its offer control will overestimate the firm's ability to exercise market power since this output is relatively costly, or is not permitted, to be withheld from the market. In reality, such must-run power is not flexible or 'dispatchable' in any practical sense and these must-run megawatts have rarely been economically withheld from the market.[60]

To account for these factors, the Adjusted RSI metric is calculated as follows:

$$\text{Adj. RSI}_{\text{jh}} = \frac{\left(\text{Total Supply}_{\text{h}} - (\text{Supply Cont}_{\text{jh}} > \$0)\right)}{\text{Total Demand}_{\text{h}}}$$

Where the $Adj.RSI_{jh}$ is the adjusted RSI for participant j in hour h and the second term in the numerator is simply the generation under a firm's offer control that is offered above $0.

The interpretation of the Adjusted RSI metric remains much the same as the generic RSI measure and a lower value of the Adjusted RSI is indicative of greater structural market power. In general, the Adjusted RSI may be a good indicator of a firm's ability to exercise market power when the economic withholding of 'must-run' generation is rare. However, the Adjusted RSI does begin to move away from a structural measure of market power to a measure of incentives.

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imports and exports power of power are simply financial contracts that will determine the net flow from one place to another (Alberta MSA (2011) "AUC Proceeding 1553").

[60] See page 12 of the Alberta MSA's 2012 Q1 report for an example of a recent exception.

For example, it is possible that 'dispatchable' generation capacity was offered at $0 because the generating corporation was short (i.e. a net buyer).

5.2.3 Adjusted RSI: Empirical Estimation

As discussed above, RSI measures use aggregated demand and supply fundamentals to highlight the extent to which a firm is pivotal in the Energy Market. The Adjusted RSI is a refinement of this metric which uses $0 offers as a proxy for a firm's 'must-run' generation. The purpose of this section is to highlight how the Adjusted RSI measure is calculated using publicly available data.

The equation used to calculate the hourly Adjusted RSI measure is given below. As shown, the three components that are required to calculate the Adjusted RSI are total supply, total demand and the supply controlled by firm j that is offered above $0.

$$\text{Adj. RSI}_{jh} = \frac{\left(\text{Total Supply}_{h} - (\text{Supply MP}_{jh} > \$0)\right)}{\text{Total Demand}_{h}}$$

As with the Residual Demand analysis, the calculation of the Adjusted RSI metric is predominantly based on the AESO's *Merit Order Snapshot – Energy* report, with adjustments also being made for wind generation and the TMR and DDS markets.

Total Supply

Total Supply is calculated as the sum of all energy offers (including imports) to the Energy Market Merit Order, plus all dispatched Dispatched Down Service (DDS), plus the total of Wind generation.

$$Total\ Supply = Total\ Supply_{ENERGY} + WIND + DDS_{DISPATCHED}$$

Total supply in the Energy Market is calculated as the sum of the Dispatched MW column for offer blocks that are dispatched, plus the Available MW column for offer blocks that are above the SMP. Imported energy blocks are included in this calculation but exports are not because exports are already accounted for in the dispatched energy. For example if there is 10,000 MW of local demand and 100 MW of export demand, Alberta generators will be dispatched to 10,100 MW. This figure includes the export demand, so adding the 100 MW again would be double counting the exports.

It is necessary to add wind generation to the supply in the merit order because wind generation is not offered into the Energy Market. For instance if there is 11,500 MW of generation available in the Energy Market and 500 MWh of wind power supplying the market, noting the market supply is only 11,500 MW yields an incorrect measure of total supply. Note that, in contrast with other generation types, wind generation rather than capacity is used. This is done so because wind generation is variable resource, dependent upon the wind blowing, and because any available wind generation must be supplied to the market, it cannot be withheld. Average hourly figures for total wind generation have been made available on the AESO's website.[61]

The amount of Dispatch Down Service ("DDS") dispatched by the AESO is also added to the total supply calculation. In hours when TMR is used by the AESO, demand in the energy market is reduced. The purpose of DDS is to offset this decrease in demand with a corresponding decrease in supply (see section 2.5.2). So when 100 MW of TMR is used, DDS decreases generation by 100 MW. However, this DDS capacity remains available to the Energy Market

[61] http://www.aeso.ca/gridoperations/20544.html

(and will be supplying power above the TMR reference price) although this capacity is not represented in the Energy market merit order. Therefore, it is necessary to add any generation dispatched down through the DDS market to get an accurate picture of the capacity that is competing in the Alberta Energy Market. Hourly DDS data is available from the AESO's Merit Order Snapshot – DDS.

Total Demand

Total demand is calculated as total demand in the Energy Market, plus the sum of all Transmission Must Run dispatched, plus the sum of Wind generation:

$$Total\ Demand = Total\ Demand_{ENERGY} + WIND + TMR_{DISPATCHED}$$

Total demand in the Energy Market is simply equal to the sum of the Dispatched MW column. Again, it is not necessary to add exports here because exports are already accounted for in the dispatch of other generation.

As with the Total Supply calculation, wind generation must be added to the Energy Market demand because wind generation is offered into the Energy Market.

The measure of total demand also includes TMR generation. Effectively, TMR is electricity demand that can only be serviced by a particular generator (see section 2.5.2 for a detailed discussion). The aggregate demand for electricity is no different in the event that 50 MW is dispatched as TMR rather than as Energy, the only difference is that a transmission constraint is binding. While this might imply that the TMR demand is in a different market, and hence not relevant, the use of DDS to offset the TMR means that TMR demand is relevant. All else equal,

an Energy Market in which 100 MW of TMR and 100 MW of DDS are dispatched has the same level of supply-demand tightness as a market with 0 MW of TMR and DDS. This intuition is reflected in the Adjusted RSI calculations because total supply includes DDS dispatches and total demand includes TMR dispatches.

Supply Controlled by a Particular Firm

The Supply Controlled by firm j is the sum of its energy offered in the Energy Market, plus the sum of its dispatched DDS, less the sum of its dispatched TMR:

$$Supply\ Cont_J = ENERGY_J + DDS_J - TMR_J$$

The first term on the right hand side of this equation is calculated as the total capacity that is offered by the firm into the Energy Market in that particular hour. Since wind power cannot be offered into the Energy Market at a price, and must act as a price-taker, wind generation was not included as under a firm's offer control. Similarly, imports and exports were not included in this term. As discussed above, a firm that is trying to influence the market price by flowing power on the interties should find its actions are offset by the actions of other firms who are seeking to profit from any available arbitrage opportunities.

Energy that is dispatched down through the DDS market is deemed to be generation capacity that is under the offer control of the firm. When generation is dispatched through the DDS market, it is effectively being offered into the Energy Market at the TMR reference price. When the energy price is below the TMR reference price, the DDS market is active and dispatched DDS units will reduce their supply accordingly. Before prices rise above the TMR reference price, the DDS market becomes inactive and all dispatched down generation must be supplying the market

(see section 2.5.2). Therefore, capacity that is dispatched in the DDS market is included as under a firm's offer control.

In contrast generation dispatched for TMR is deducted from a market participant's offer control. This is done because in the event that a unit is dispatched for TMR the unit has an obligation to supply the required energy. Under these circumstances, the applicable generation capacity is forced to run and cannot be withheld from the market. For instance, a 40 MW unit offered at $900 may be required to generate electricity when prices are $50. In addition, if this $50 price is above the TMR reference price, the firm's 40 MW of generation will not be offset by a decrease in supply through the DDS market. In this way, a firm's ability to influence prices with capacity that is dispatched as TMR is limited.

For units that are controlled by two participants, such as some units subject to Power Purchase Arrangements (PPAs) and joint ventures (Genesee 3 and Keephills 3), some assumptions were necessary to allocate the unit availability between the participants.

For some of the units subject to a PPA, the PPA Owner has retained the offer control of any excess energy / increased capacity that is available above the unit's Target Availability (see section 3.4). For these units it was assumed that PPA Buyer would have complete control over all capacity available up to the unit's Committed Capacity. Any available capacity above this level is assumed to be controlled by the Owner. This effectively assumes that the PPA Owner would incur any fall in availability first. DDS offers from PPA units are attributed to the PPA Buyers, as is any dispatch for TMR. For Genesee 3 and Keephills 3, all aspects are split evenly between Capital Power and TransAlta.

Once the total supply controlled by firm j has been calculated the supply controlled by firm j that is priced above $0 is calculated by subtracting the generation that is offered into the Energy Market at a price of $0:

$$\left(\text{Supply Cont}_{\text{J}} > \$0\right) = \left[\text{Supply Cont}_{\text{J}} - \left(\text{Supply Cont}_{\text{J}} = \$0\right)\right]$$

5.3 Additional Considerations - Incentives and Expectations

5.3.1 Ability vs. Incentives

The reader should note that the two measures developed in this thesis are both structural measures of market power. These structural measures examine the ability of suppliers to influence market prices in the Alberta Energy market through their offer strategies. Without commercially sensitive data, it is not possible for the thesis to examine the profitability of exercising market power. This is an important distinction since the incentives for a profit-maximizing generator to exercise market power may not be consistent with the firm's ability to do so. A generator's incentives to exercise market power will depend upon its 'net exposure' to the real-time market price. A generator's net exposure (or 'portfolio position') measures the amount of power that the firm is selling into the prevailing market price. A generator can be thought of as 'long' (a net seller) or 'short' (a net buyer).

Intuitively, generators that sell a large proportion of their capacity at fixed-prices (i.e. prices that are independent of real-time market prices) will have less incentive to increase wholesale market prices because their revenues are less dependent upon these prices. For example, a large generator that faces no net exposure to the hourly pool price will be largely indifferent to the prevailing hourly price and will optimally offer competitively. In contrast, generators that buy a

large amount of power at a fixed price, and settle this against the real-time price, will have a higher incentive to increase the real-time price.

Using the economic theory of profit-maximization outlined in section 5.1 it is simple to explain how the Residual Demand and the RSI measures can be altered to examine a generator's incentives to exercise market power. The following equation shows the profit-maximizing condition for a firm facing the residual demand function $RD(p)$ and with fixed-price sales of Q_F (fixed-price purchases of power can simply be expressed as negative sales). As shown, the firm maximizes profits by considering the elasticity of its net residual demand function:

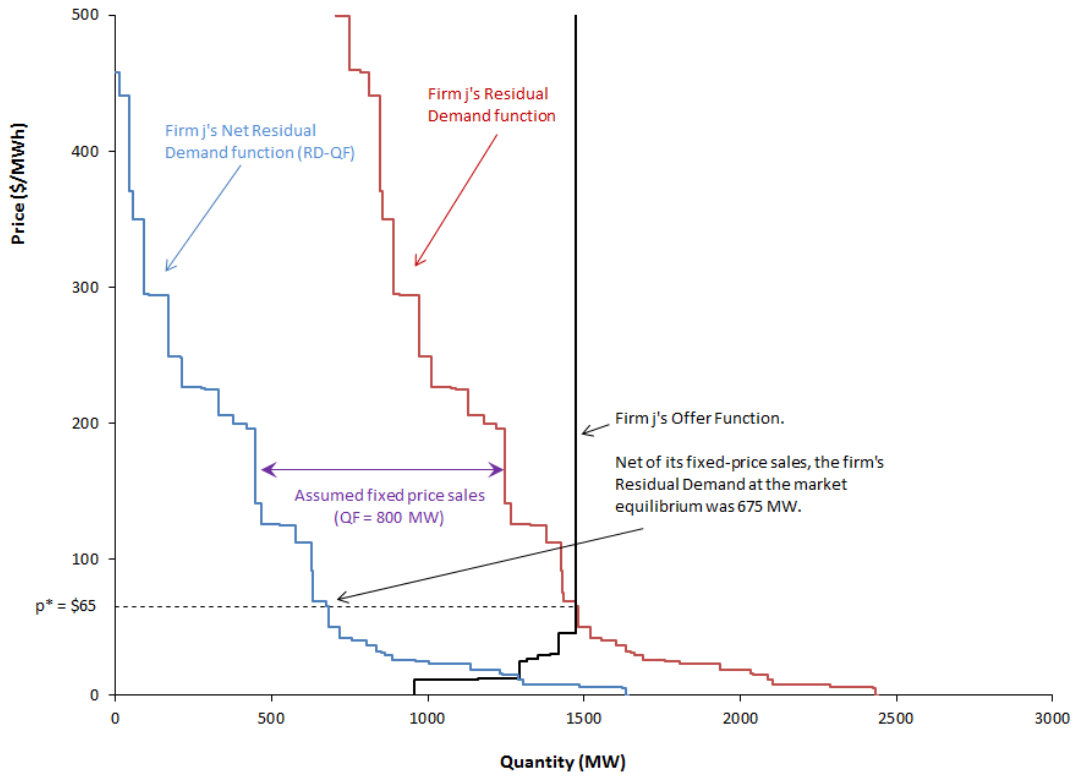
$$\frac{p-c}{p} = -\frac{(RD(p)-Q_F)}{p}\frac{\partial p}{\partial(RD(p))}$$

The above equation highlights that as the generator's fixed-price sales increase it will optimally offer at prices that are closer to its marginal cost. The intuition behind this is simple. For every MWh that is sold forward, the firm is effectively committed to buying this energy from the wholesale market and selling it to another party for a fixed price. By increasing the wholesale market price, the generator's only impact on this transaction is to increase the costs of buying the energy. Therefore, a large generator with market power that has sold its capacity at fixed-prices will optimally bid competitively. Indeed, a generator that is short to the wholesale market price will optimally generate energy at prices that are below the firm's marginal cost in order to lower the buying costs for the firm's fixed-price sales.

To highlight the impact of a firm's exposure to the pool price in practice, Figure 22 is used to illustrate a hypothetical example. In this example, firm j's Residual Demand function is illustrated by the red line and the firm's offer curve is shown in black. The blue line illustrates

the firm's Net Residual Demand function, which is given by the firm's residual demand less its fixed-price sales (assumed to be 800 MW).

Figure 22: The Impact of Fixed-Price Sales on a Generator's Incentives



The residual demand function faced by the firm shows that the supplier could have increased the market price from $65 to $140 by economically withholding 206 MW of generation. By reducing its supply from 1,475 MW to 1,270 MW (or by 14%) the firm could have realized a 216% increase in the market clearing price. In this example, the firm's generation revenues would have almost doubled from $96,000 to $178,000. However, given its fixed-price obligations this price increase is also detrimental to the firm and the exercise of market power would have increased the costs of its fixed-price sales by ($140 - $65) * 800 = $60,000. On a net basis then, the generator's revenues would still have increased (by ~$20,000) as a result of this strategy.

This example serves to highlight that as suppliers have an increasing amount of fixed-price sales, their incentives to exercise unilateral market power will decrease. In particular, a profit maximizing generator with fixed-price obligations to supply, or to buy power, will optimize its output decisions by considering its net residual demand function. Using the theoretical underpinnings outlined in sections 5.1 and 5.2 it is clear that the Residual Demand and the Residual Supplier Index measures can both readily be adapted to account for a firm's fixed-price obligations and other incentives by using the Net Residual Demand function.

In Alberta, a generator's exposure to the resulting pool price will vary depending upon a number of physical and financial factors – these factors are outlined in the following section. Using publicly available data alone, it is not possible to measure the incentives that a generator has to exercise market power because a firm's net exposure cannot be calculated without detailed information on a generator's financial trades and bilateral contracts - which are not publicly available. Consequently, the metrics developed in this thesis measure the ability a generator had to influence the market price, not the incentives the generator had the ability to influence the market price profitably.

5.3.2 Factors which Influence the Incentives of Generators in Alberta

Firms participating in the Alberta power pool will face a varying degree of exposure to pool price as their physical and financial portfolios change, and the net exposure of Alberta's larger generators to the pool price will meaningfully impact their conduct in the real-time energy market. The following is a list of factors that will influence a generator's exposure to the hourly price:

Power Sales at real-time price: a generator's supply into the power pool will increase the generator's exposure to the hourly pool price. For example, 500 MW of energy sales will increase a generator's exposure to the pool price by 500 MW. Since available but undispatched capacity in the energy market does not receive any payment, these undispatched megawatts do not influence a generator's exposure to the hourly pool price. It is also worth noting that wind generation can increase a firm's length significantly, even though wind generation is not dispatched in the energy market.

Retail Market Sales: a large amount of fixed-price retail sales will lower a generator's exposure to the hourly pool price. By selling power in the retail market at a fixed price, the firm is effectively buying this power from the pool and selling it for the contracted price.[62] It is important to note that a vertically integrated 'gentailer' may face a varying degree of pool price exposures depending upon the load profile of its contracted retail obligations. For instance, if a large proportion of the contracted sales are to residential consumers, the firm's retail load obligations will change significantly from peak to off-peak since the load profile of residential consumers is variable.

Forward Market Trades: generators can alter their exposure to the hourly pool price by buying and selling forward contracts at a fixed price. By selling power forward at a fixed price the generator 'hedges' its exposure to pool price and will have less incentive to increase the real-time market price as a result. In contrast a generator can increase its exposure to the pool price by buying power forward at a fixed price and selling this power into the real-time market. The

[62] A fixed price refers to a contract price that is not a direct function of the hourly pool price. If a firm is selling generation in the retail market at pool price, these 'flow through' sales will not impact the generator's exposure.

majority of forward trades in Alberta are monthly contracts, and it is not uncommon to see a firm's offer strategies alter notably from one month to the next as their exposure changes.

Ancillary Services / Operating Reserves: the prices in the Alberta reserves market are indexed directly to the Alberta pool price. Therefore, a generator selling 100 MW into the Ancillary Services market will be 100 MW longer to pool price if the indexed AS price is greater than $0, but the generator will face no additional exposure if it receives no revenues from the AS sales (if the the resulting AS price is >= $0).

Imports and exports: imports into Alberta will increase a generator's exposure to the pool price while exports from the province will reduce their exposure.

Bilateral Contracts: generators can buy or sell power directly with another participant via bilateral contracts. For load participants, the principal advantage of these contracts is that they can be customized or tailored more so than a financial hedge or retail purchase. For generating companies, the customized nature of bilateral contracts means that the effect of the contract on their net exposure will be contract-specific.

Outages and Availability Incentive Payments: Unit outages will tend to decrease a firm's exposure to the pool price because the firm will sell less power when its units are on outage. For coal units under a PPA, the Availability Incentive Payments (AIPs) are a unique consideration for Owners and Buyers. The AIP is a financial obligation under the PPA, which is intended to incentivise the PPA Owner to operate the plant in an efficient manner in order to maximize the Availability of the unit to the PPA Buyer. The equation below shows the AIP revenues flowing from Buyer to Owner:

$$\mathrm{AIP_{Uh}} = (\mathrm{AA_{Uh}} - \mathrm{TA_{UY}}) * \max\{0, (\mathrm{RAPP_{DP}} - \mathrm{VC}_{Uh})\}$$

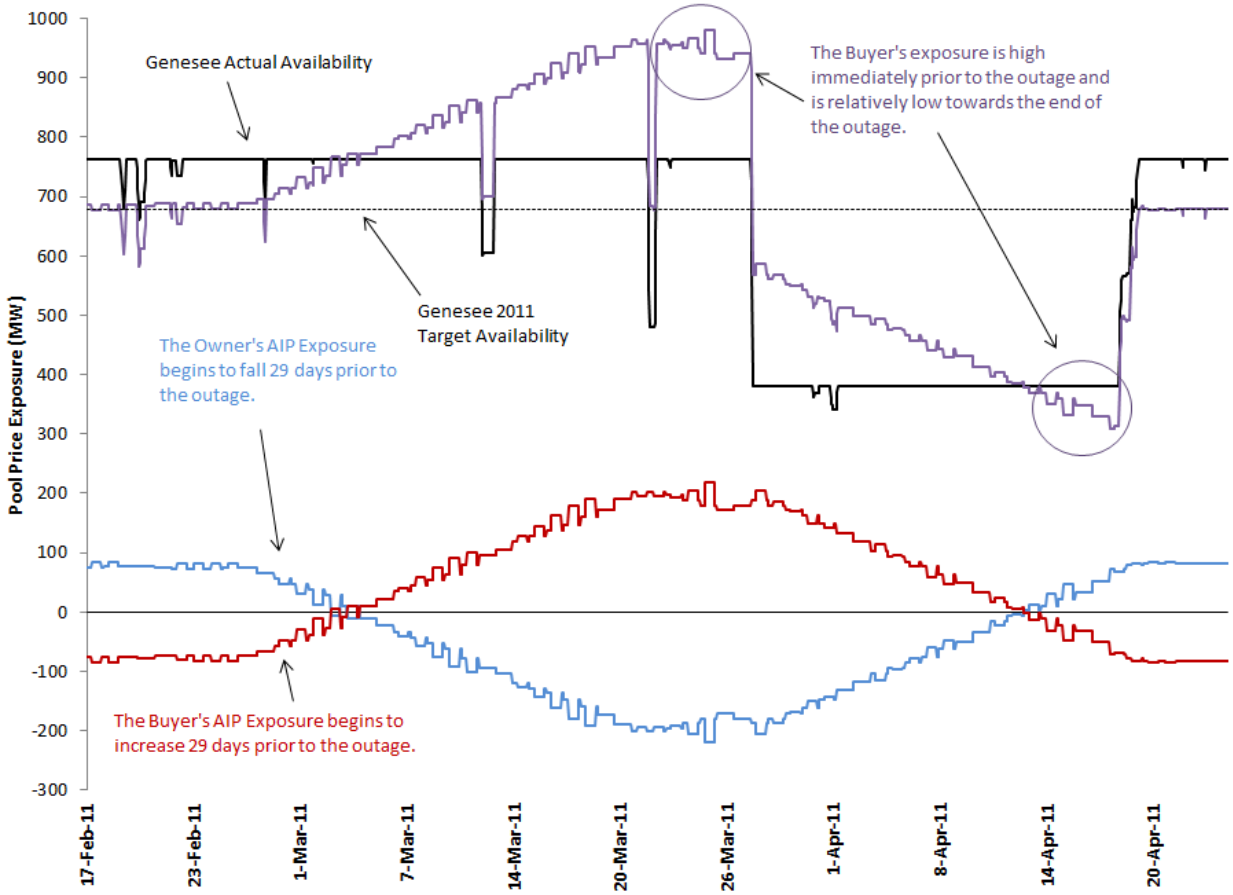
As shown, in hours when the unit's Actual Availability (AA) is above the specified Target Availability (TA) the payment is positive meaning that the PPA Owner receives payment from the Buyer. Conversely, in hours when the unit's Actual Availability is below its Target Availability, the payment is from the Owner to Buyer. In this manner, the PPA Owner is rewarded when the availability of the unit is high and is punished in hours when the unit's availability is low.

As well as the difference between the unit's Actual and Target Availability, the size of the AIP will depend on the difference between the 30-day Rolling Average Pool Price (RAPP) and the unit's variable costs (VC).[63] For the majority of hours, coal units are available above their Target Availability, and in these hours the AIP tends to be a relatively small transfer from Buyer to Owner. However, when a large unit is on outage when RAPPs are high, the hourly AIP is a significant transfer from Owner to Buyer.

Given that the Rolling Average Pool Prices are a function of the pool prices posted on that day and in the previous 29 days, the exposure of the PPA Owner and Buyer to future RAPPs can have important implications for their current exposure to the pool price. The intuition here is simple - by effecting pool price today, the PPA parties can impact the future RAPP and, by doing so, the parties can impact the upcoming Availability Incentive Payments.

[63] The Rolling Average Pool Prices are calculated daily based on the average prices that occurred on the current day and in the previous 29 days. Two daily prices are determined, peak and off peak, with peak hours being Alberta business days from 7am until 9pm.

Figure 23: Pool Price exposure and Availability Incentive Payments an example



To illustrate the importance of these incentives, Figure 23 shows the implication of a 20-day planned PPA Outage on a Buyer's exposure to the hourly pool price. The example uses an outage at Genesee in early 2011. The target availability for the two units in the Gensee PPA is 680 MW and the Buyer normally has 760 MW of capacity made available. Typically then, the PPA Buyer has an exposure to the RAPP of (680 - 760) = -80 MW. However, during the outage, one of the units is completely unavailable so the PPA net exposure to the RAPP is (680 – 380) = 300 MW. Because RAPPs are calculated using realized pool prices, this change has an effect on the PPA Buyer's pool price exposure.

The red line illustrates the impact of the Availability Incentive Payment on the Buyer's exposure to the current pool price. As shown, the impact of the outage is to increase the Buyer's exposure to the current pool price. That is, by increasing the current pool price, the PPA Buyer can increase the AIPs that will be received during the outage. This indirect effect will increase as the beginning of the outage approaches because the current price will be rolled into a greater number of the outage hours.

During the outage itself, the effect of the AIP on the Buyer's pool price exposure is muted by the fact that the unit is unavailable (as shown by the purple line). The effect of AIPs will also decline as the end of the outage approaches because the number of future hours where the Buyer faces a 300 MW exposure to the RAPP falls.

The blue line illustrated on the Figure, illustrates the impact of the PPA outage to the pool price exposure of the Owner. Intuitively, the PPA Owner will face a lower exposure to the pool price as a result of the outage because by lowering pool prices the Owner can reduce the AIP costs of the outage. In summary, the AIPs can have a meaningful effect on the exposure of the parties in the PPA. This effect will be most pronounced at the beginning of a prolonged outage. During these periods the prevailing pool prices will get rolled into future RAPPs which determine the magnitude of the AIPs that will occur from Owner to Buyer during the outage.

5.3.3 Generator Expectations

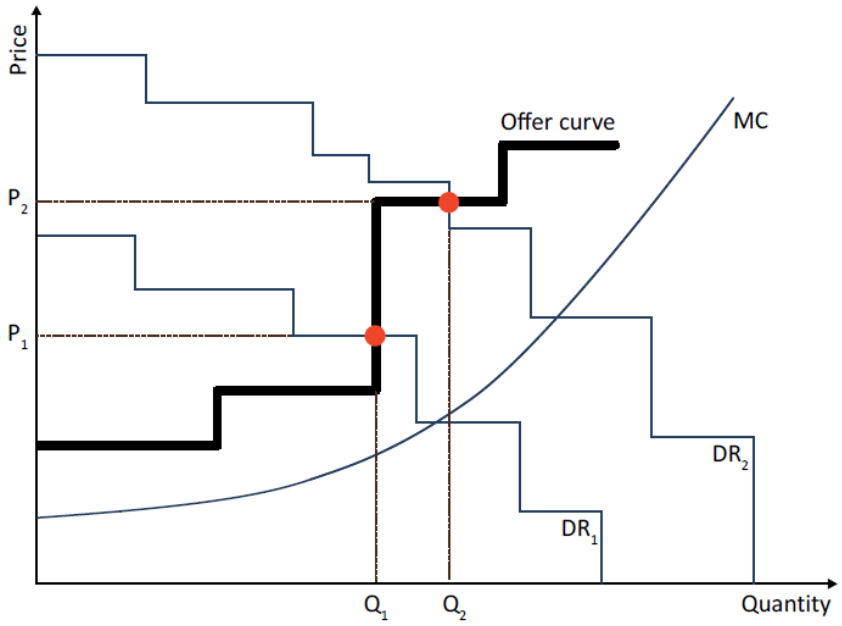
The two measures of structural market power developed in the thesis are both *ex-ante* measures - both illustrate the ability that a firm *had* to exercise market power in a particular hour. The profit –maximizing theory outlined in section 5.1 assumes that the firm knows its residual demand function with certainty when submitting its final offer curve. In practise however, the residual demand function to be faced by a generator is not known with certainty at the T-2 cut-off, and a firm's residual demand function may change unpredictably as generating units trip and as other firms change their offers. Therefore, suppliers to the wholesale market face uncertainty when submitting their final offers at T-2.

However, the economic justification for using a firm's residual demand function to measure its market power carries over to the case that suppliers do not observe the actual residual demand curve they face at the time they submit their offers to the wholesale market (see Wolak and McRae (2012)). In particular, while Alberta's larger generators may not know with certainty the residual demand functions that they will face when submitting their final offers, these experienced participants will have a very good idea of the possible residual demand curves that they might face. As noted in section 3.5 the Alberta wholesale market is very transparent and the AESO publishes a large and detailed set of market data in real-time. As a result, power suppliers in Alberta are well informed and in a good position to know the possible residual demand functions that they may face in a few of hours.

For each potential residual demand curve the firm can determine the profit maximizing output by using the process detailed in section 5.1. This idea is shown diagrammatically in Figure 24. In this simple example, the profit maximizing firm faces two potential residual demand functions

when submitting its offer function. For each possible residual demand function the firm can determine the profit-maximizing price-quantity equilibrium (shown by the red circles). The firm can then submit an offer curve that passes through both of these points and thus ensure that in either scenario, DR_1 or DR_2, the supplier is maximizing its profits.

Figure 24: A Simple Example of Expected Profit-Maximization



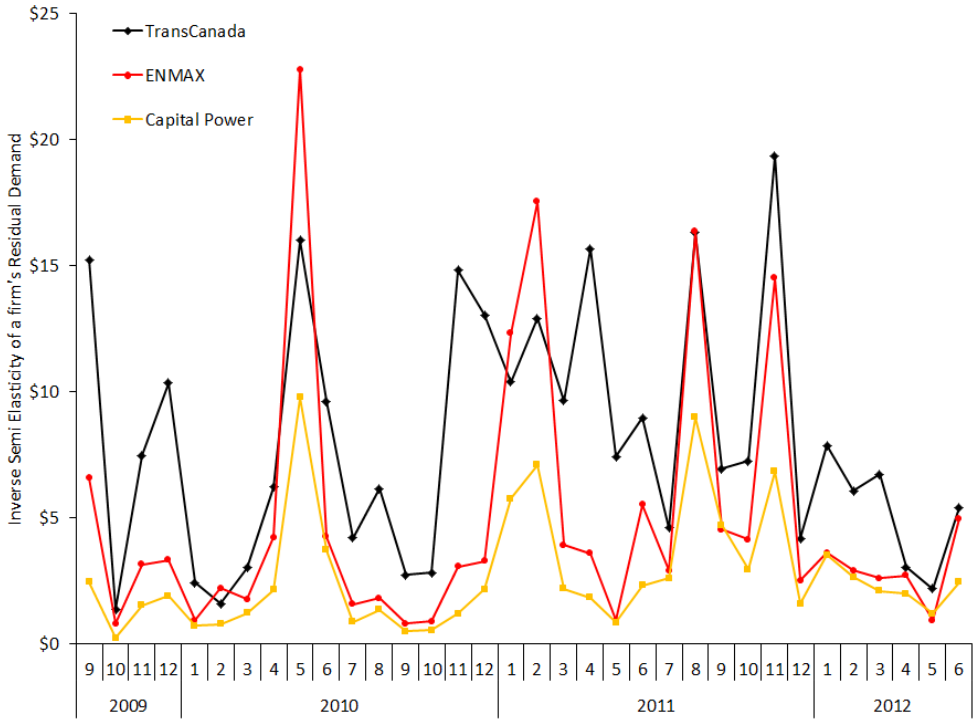
It should be noted that a firm's ability to offer in an expected profit maximizing manner may be constrained by operational characteristics or by ISO market rules. As a consequence of these constraints, there will be hours in which market participants cannot offer a supply function that passes through the profit-maximizing price-quantity pair for each potential residual demand function. In such cases the supplier must estimate the probability of each residual demand function, and maximize profits over the resulting distribution (see Wolak 2000 for a detailed discussion).

Chapter 6: Empirical Results and Analysis

6.1 Market Power Estimates Over Time

Figure 25 below illustrates the monthly average of the hourly Residual Demand metric for three of the larger generating companies in Alberta over the sample period. As discussed in section 5.1, the inverse semi-elasticity of a firm's residual demand function estimates the price effect of the firm withholding 1% of its dispatched generation. The analysis shows that TransCanada, Capital Power and ENMAX all had notable market power in certain months of the sample period while in other months the firms were relatively limited in their average ability to influence price.

Figure 25: Monthly Averages of Residual Demand Estimates



ENMAX is shown to have had significant market power in May 2010 when the firm's average inverse semi-elasticity for the month was over $20. ENMAX also realized market power peaks

in January, February, August and November of 2011. The Figure illustrates that on average ENMAX's market power outside of these peak months was relatively limited.

The inverse semi-elasticity metric also shows that TransCanada and Capital Power had many of the same monthly market power peaks as ENMAX (May 2010, February 2011, August 2011 and November 2011 are examples). In addition, the metric highlights September 2009, December 2009, and November 2010 - April 2011 as periods when TransCanada's average market power was relatively high.

Figures 26 and 27 illustrate how the inverse of the Adjusted RSI metric changed over the sample period for the 5 largest generating firms in Alberta. The inverse of the Adjusted RSI is plotted and analyzed throughout this section for ease of interpretation; an increase in the inverse adjusted RSI implies greater structural market power. This inverse Adjusted RSI metric shows the extent to which a firm's priced generation was pivotal to the clearing of the energy market in a particular hour. When the hourly Adjusted RSI metric is greater than 1, the firm's priced generation (i.e. generation offered above $0) was pivotal to the clearing of the Energy market.

Figure 26: 10-day Moving Averages of the Maximum Daily Adjusted RSI

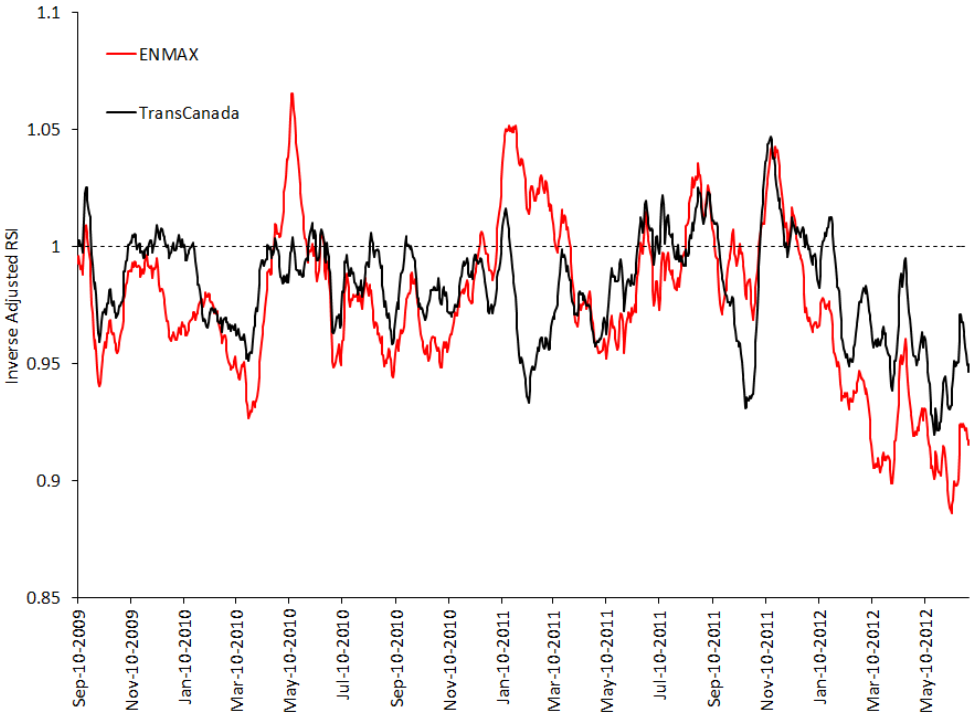
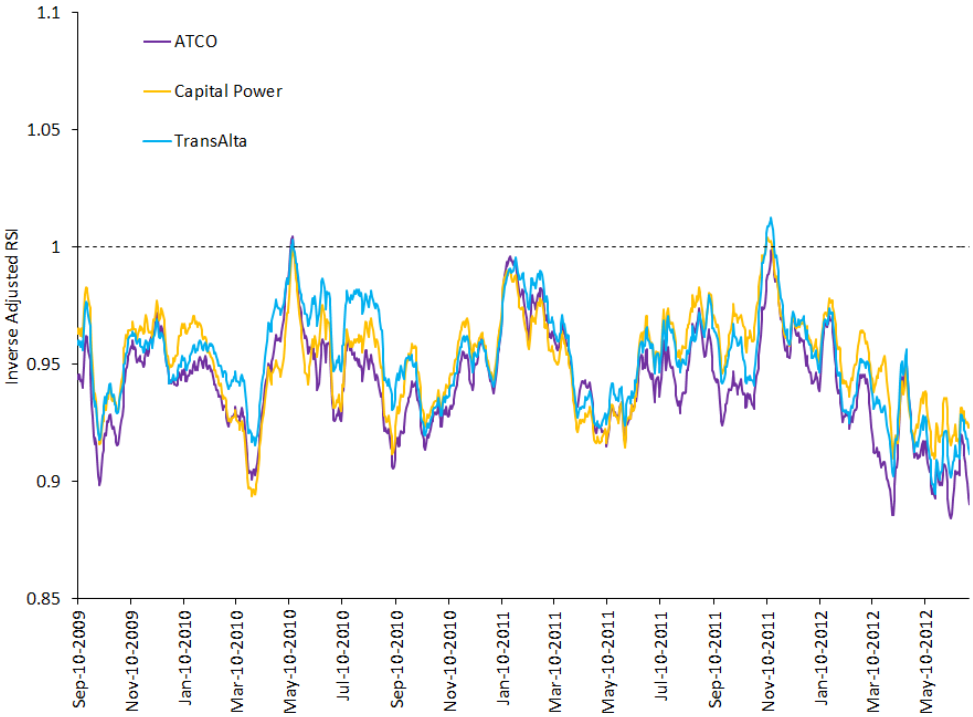


Figure 27: 10-day Moving Averages of the Maximum Daily Adjusted RSI



As with the residual demand analysis, the adjusted RSI metric shows that the ability of each firm to exercise market power varied across the sample period. In addition, the Adjusted RSI analysis highlights many of the same peaks as the residual demand estimates. For example many of the larger firms saw peaks in their ability to exercise market power during May of 2010 and in January-February, August and November of 2011.

It is worth noting that many of these market power peaks were the result of supply-side constraints in the Alberta electricity market. For example, the MSA's Q2 report of 2010 shows that transmission constraints were a significant factor in May 2010, and the extent of these transmission issues was significant - in some hours up to 1,000 MW of generating capacity was constrained and unavailable to the market. In terms of unilateral market power, this event effectively caused a meaningful fall in the availability of baseload generation, thereby shifting the market equilibrium onto the steeper portion of the supply function. In this area of the supply function relatively small changes in generation can have a meaningful impact on market prices. This intuition is demonstrated by the fact that both market power measures illustrate peaks in the market power of the larger suppliers in this period.

In a similar vein, operational issues at baseload coal units were a significant factor in explaining the market power peaks observed in January, February, August and November of 2011. Most notably, the Sundance 1 and 2 units were, and remain, on an extended outage because of issues with boiler corrosion. These units account for 576 MW of coal-fired capacity. The plants went offline in mid-December of 2010 and early in January of 2011 TransAlta issued a notice of forced majeure to the Buyer of the Sundance A PPA. From Figures 26 and 27 it is apparent that

these outages significantly increased supplier market power in Alberta's electricity market during the first two months of 2011, when cold temperatures meant market demand was high.

6.2 The Distribution of Market Power

It is important to note that the ability of generator's to exercise market power in Alberta is often limited to a relatively few hours. For example, Figure 28 shows the distribution of the Residual Demand analysis for the two largest firms across the sample period. The distribution curves illustrate that both TransCanada and ENMAX faced a meaningful amount of competition at the margin in the majority of hours. For example, the median of TransCanada's semi-elasticity measure is around $0.9 (see Table 9 for some summary statistics). This implies that in 50% of the hours, TransCanada's influence on the market price with 1% of its dispatched generation (generally 15 – 20 MW) is less than $1. In 80% of the hours this Figure is less than $2.14 for TransCanada and $1.39 for ENMAX.

The distribution curves in Figure 28 also show a distinct 'hockey-stick' shape. The steep slope on the right hand side implies that in the few hours that the larger firm's do have market power, their ability to influence the market price with a small amount of their generation is high. For instance, in the top 5% of hours TransCanada's residual demand estimates imply that the firm could have influenced the pool price by more than $30 with only 1% of its dispatched generation, and in 1% of hours the firm's ability to influence prices with 1% of its output was more than $160 (see Table 9).

Figure 28: The distribution of the Residual Demand metric for ENMAX and TransCanada

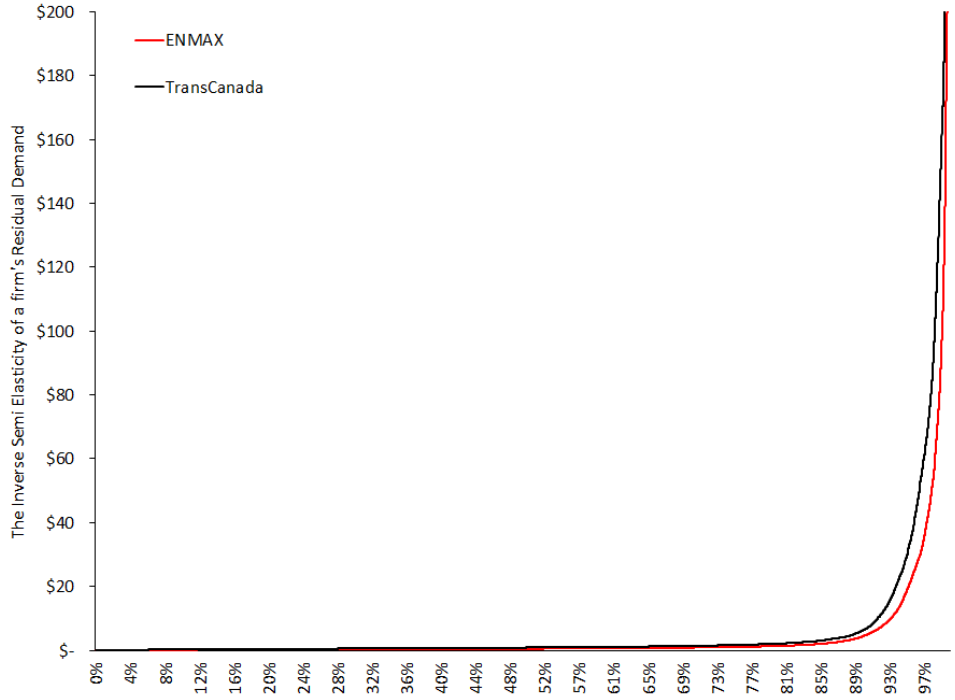


Table 9: The distribution of the Residual Demand estimates - Summary Statistics

Percentile	ATCO	Capital Power	ENMAX	TransAlta	TransCanada
5%	$0.04	$0.09	$0.14	$0.03	$0.18
10%	$0.05	$0.12	$0.19	$0.06	$0.28
50%	$0.14	$0.32	$0.52	$0.23	$0.87
80%	$0.38	$0.84	$1.39	$0.60	$2.14
95%	$7.41	$11.46	$19.45	$9.56	$30.75
99%	$42.80	$52.39	$97.01	$50.15	$161.19

As shown, the top few hours were an important driver in determining the a firm's average ability to influence market prices over the sample. To see this, Figure 29 illustrates how the mean and median of ATCO's market power changed over the sample period. Figure 30 shows the same analysis for TransCanada. Both Figures highlight that the mean residual demand estimates often peak significantly above the median, showing that these market power peaks are often driven by the firms' market power being relatively significant in a few hours.

Figure 29: The Mean and Median of the Residual Demand Analysis for ATCO during peak hours

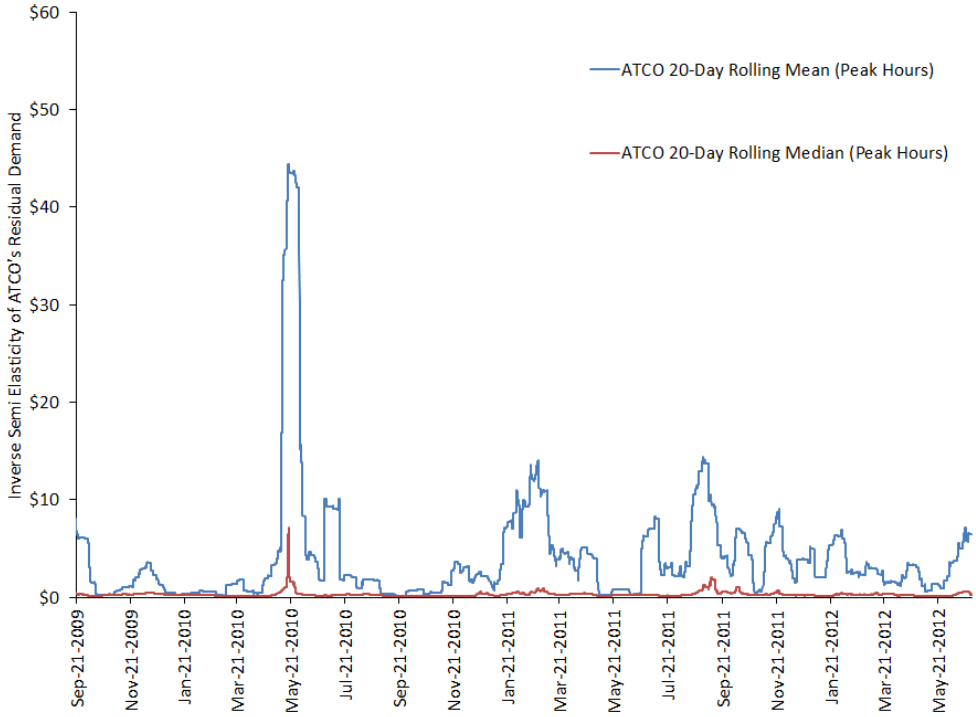


Figure 30: The Mean and Median of the Residual Demand Analysis for TransCanada during peak hours

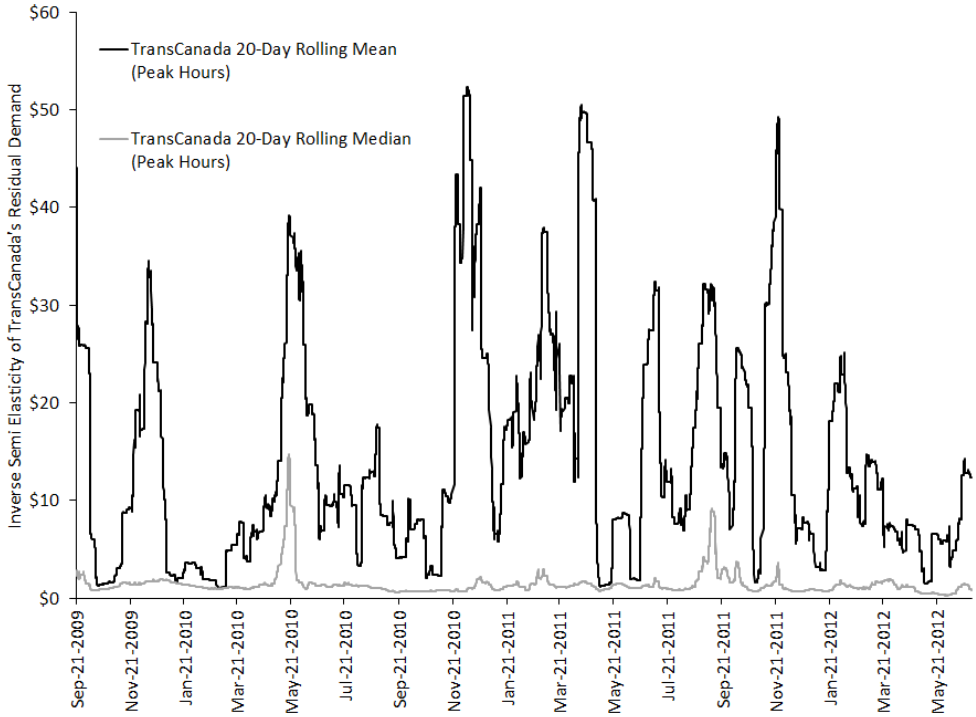


Figure 31 below shows the distribution curves for the Adjusted RSI metric. Again, the inverse adjusted RSI is reported for ease of interpretation; an increase in the inverse adjusted RSI implies greater structural market power. As with the Residual Demand analysis, the Adjusted RSI approach shows that the majority of hours in the Alberta wholesale market are quite competitive. For example, the Adjusted RSI metric is less than 1 in over 90% of hours for the two largest firms in the market (Table 10).

Figure 31: The distribution of the Adjusted RSI measure for the 5 largest generators in Alberta

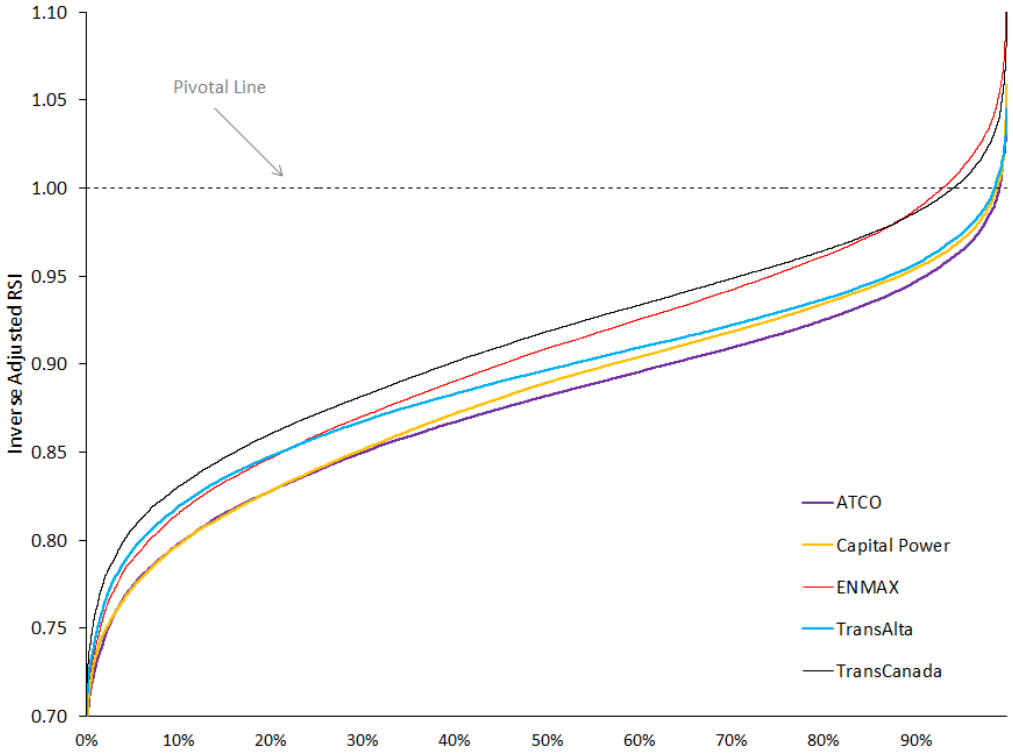


Table 10: The Percentage of hours in which generators had an Inverse Adjusted RSI above a certain level

Inverse Adj. RSI	ATCO	Capital Power	ENMAX	TransAlta	TransCanada
0.95	9%	12%	26%	13%	29%
1	0.8%	1.1%	7.0%	1.4%	5.9%
1.05	0.0%	0.0%	1.0%	0.0%	0.5%
1.1	0.0%	0.0%	0.1%	0.0%	0.0%

Figure 32 shows how the distribution of market power, as measured by the residual demand approach, for ENMAX and TransCanada changed across hours of the day. The Figure shows the median, 75th and 90th percentile for each hour of the day. As one would expect, the Figure highlights that generator market power is highest during on-peak hours when demand for electricity it relatively high. The Residual Demand analysis again highlights that the market power of the larger generators in Alberta tends to be concentrated in relatively few hours, and that these few hours tend to occur during on-peak periods when demand is high. In addition, the Figure shows that the evening ramp in market demand during the winter months is an important factor in determining generator market power.

Figure 32: The distribution of the Residual Demand estimates across weekday hours for ENMAX and TransCanada

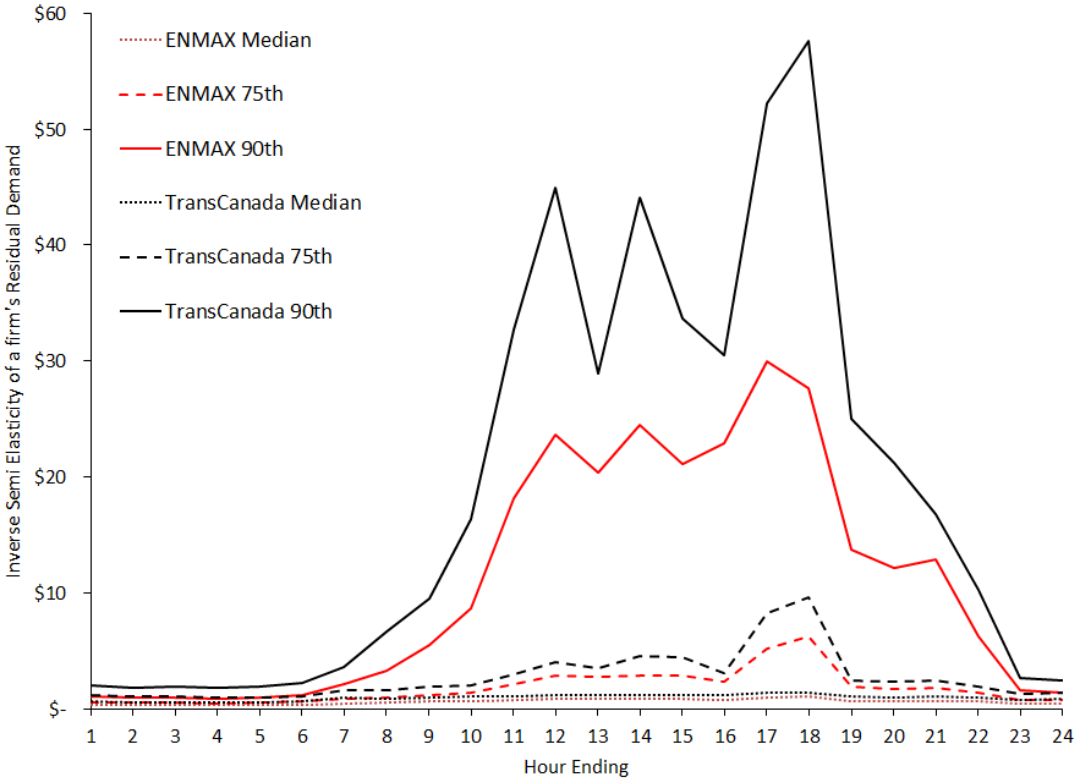
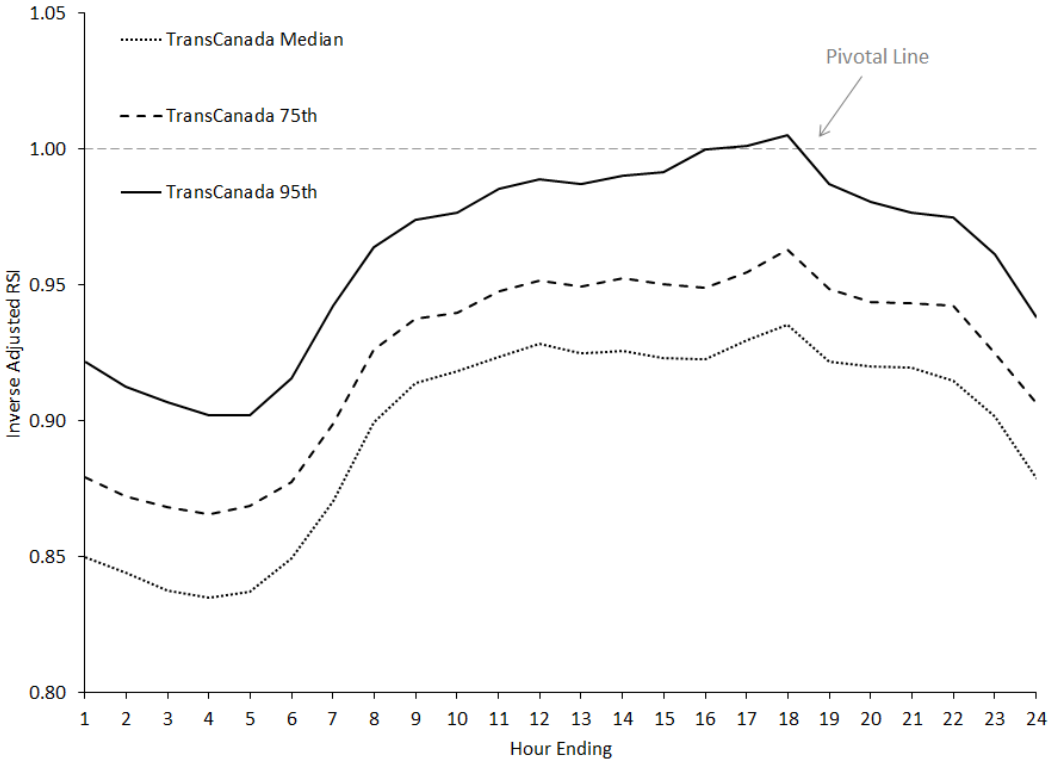


Figure 33 illustrates the same hourly analysis for TransCanada's market power using the Adjusted RSI measure. As with the Residual Demand analysis, the Adjusted RSI measure shows an important difference between the peak and off-peak periods – highlighting that the larger firms normally have very little ability to influence market outcomes when demand for electricity is low. The Adjusted RSI analysis also highlights the evening peak in market demand which occurs around Hour Ending 18 during winter months. In addition, comparing the median of the Adjusted RSI with the 95th percentile illustrates a similar point to the Residual Demand measure; the market power of the larger firms in Alberta is generally limited to a few on-peak hours.

Figure 33: The distribution of TransCanada's Adjusted RSI across weekday hours

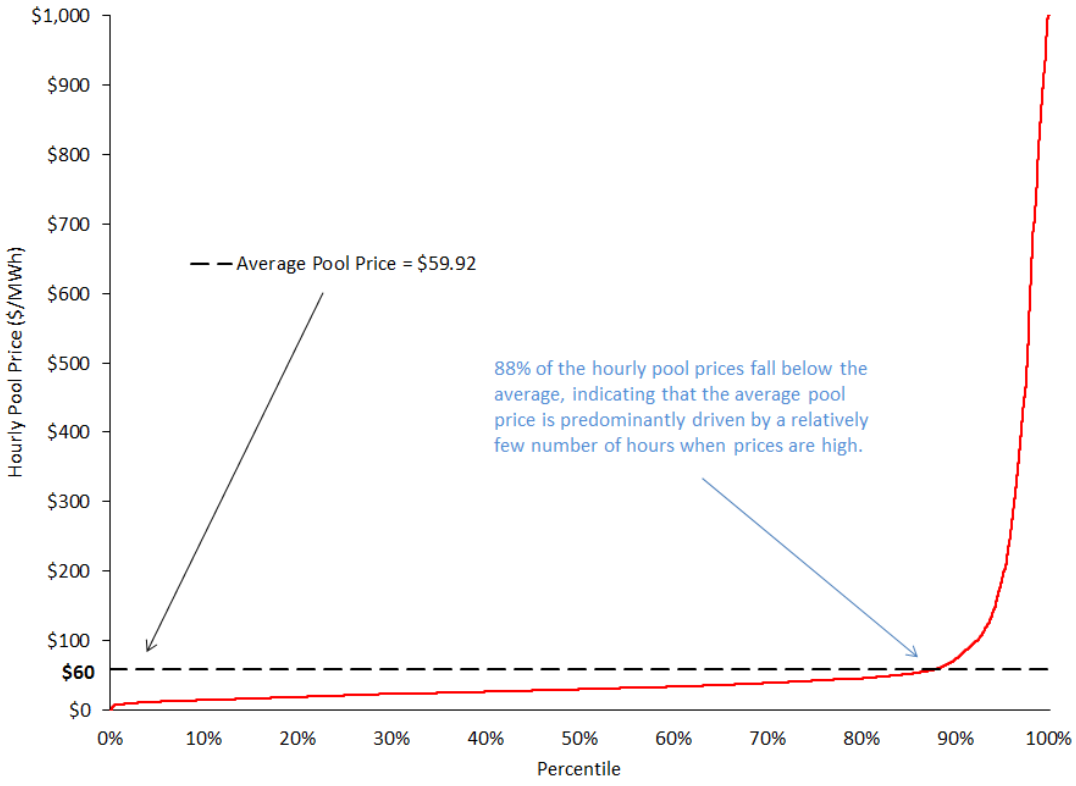


6.3 Alberta Electricity Prices, Market Fundamentals and Market Power

6.3.1 The Distribution of Electricity Prices in Alberta

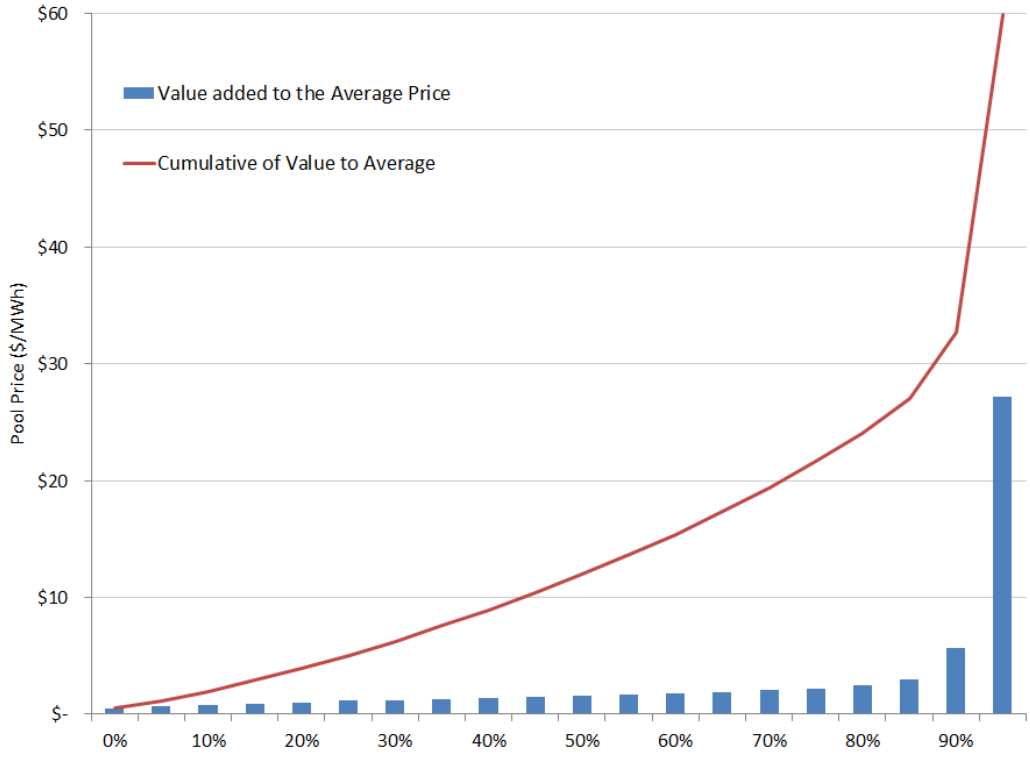
The average hourly pool price for electricity in Alberta from September 1st 2009 through June 30th 2012 was $59.92/MWh. During this sample period, hourly prices ranged all the way from the price-floor at $0/MWh to the price cap at $1,000/MWh. The distribution of hourly pool prices across the sample period is illustrated by the red curve in Figure 34. As shown, the distribution of pool prices is skewed significantly to the right hand-side (i.e. there are a few hours where pool prices are well above the normal level). For example, the median value of hourly pool prices in the sample period was $30.42, or only 50% of their mean. Indeed, for almost 90% of the hours within the sample period hourly pool prices fell below their resulting mean.

Figure 34: The Distribution of Hourly Pool Prices over the sample period



To illustrate the implications of this price distribution, Figure 35 shows the contribution that each 5-percentile group made to the resulting average pool price within the sample period.[64] For example, the hours within the 80 - 85th percentile of pool prices contributed $2.46, or 4%, to the mean pool price of $59.92. The Figure illustrates that the top 5% of hours within the sample period contributed significantly to the resulting average. In particular, the top 5% of hours within the sample period accounted for $27, or 45%, of the resulting average pool price. The top 10% of hours accounted for $33, or 55%, of the average pool price within the sample period. The other way of looking at this is that 90% of hours within the sample period contributed less than 45% to the resulting average price.

Figure 35: The Value that 5 percentile groups made to the resulting Average Pool Price



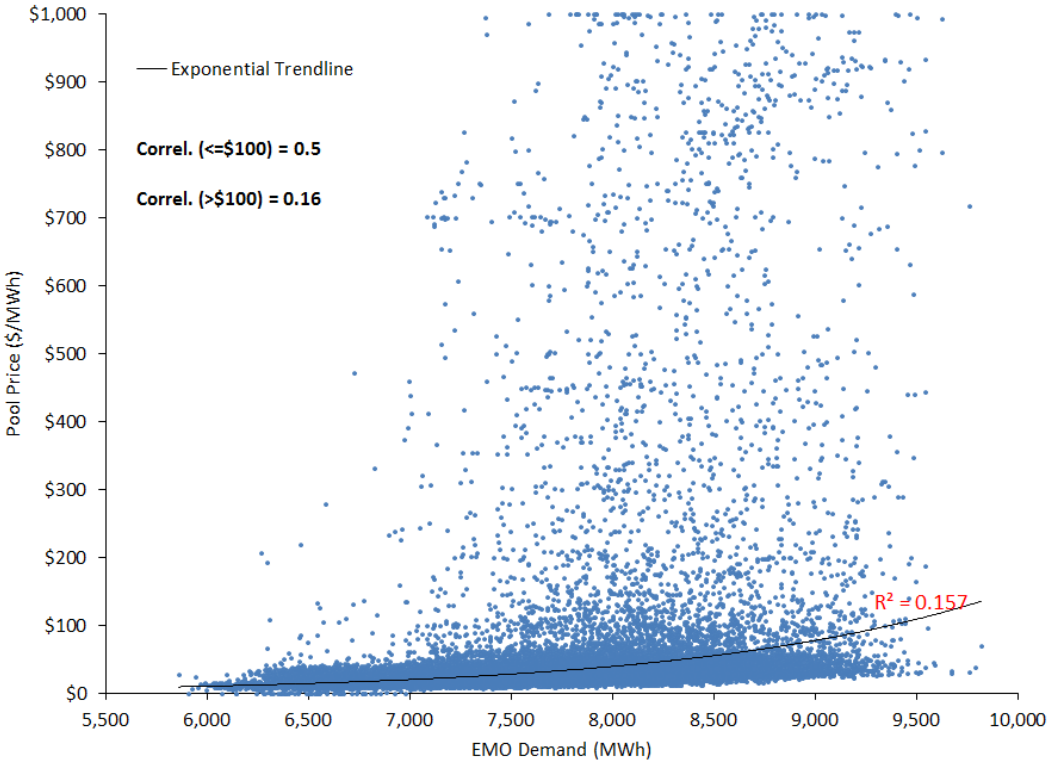
[64] The value contributed to the average by each group is calculated by totalling all the pool prices that fell within each 5 percentile group and dividing by the total number of hours in the sample period.

6.3.2 Pool Prices, Market Demand and the Price of Natural Gas

In a competitive market, the demand for electricity will be a principal factor in determining market prices. As demand increases, higher cost generators will be required to generate electricity and so prices will be higher as a result. Conversely, as demand falls, only low-cost generators are dispatched on and so prices will tend to be lower. In addition, the prevailing costs of generating electricity will be an important factor in determining prices when the market is competitive. As the costs of generating power increase, suppliers will offer their electricity at a higher price, causing market prices to increase. Conversely, as input costs decrease, generators will lower their offer price, causing market prices to fall.

As shown by Figure 36, there is a positive relationship between the demand for electricity in the Alberta energy market and the prevailing pool price. The scatterplot illustrated in Figure 36 also highlights that market demand is most useful for explaining the variations in market prices below a certain level. For example, using the exponential line-of-best-fit illustrated, market demand alone can only explain market prices of up to ~$100 and there are a number of high-priced hours which cannot be explained by variations in market demand. Another simple way of highlighting this is to look at correlation coefficients. When analyzing hours in which the market price was less than $100, the correlation coefficient between the hourly demand and the resulting Pool Price is 0.5. In contrast, when analyzing hours in which the market price was greater than $100, the same correlation coefficient falls to 0.16.

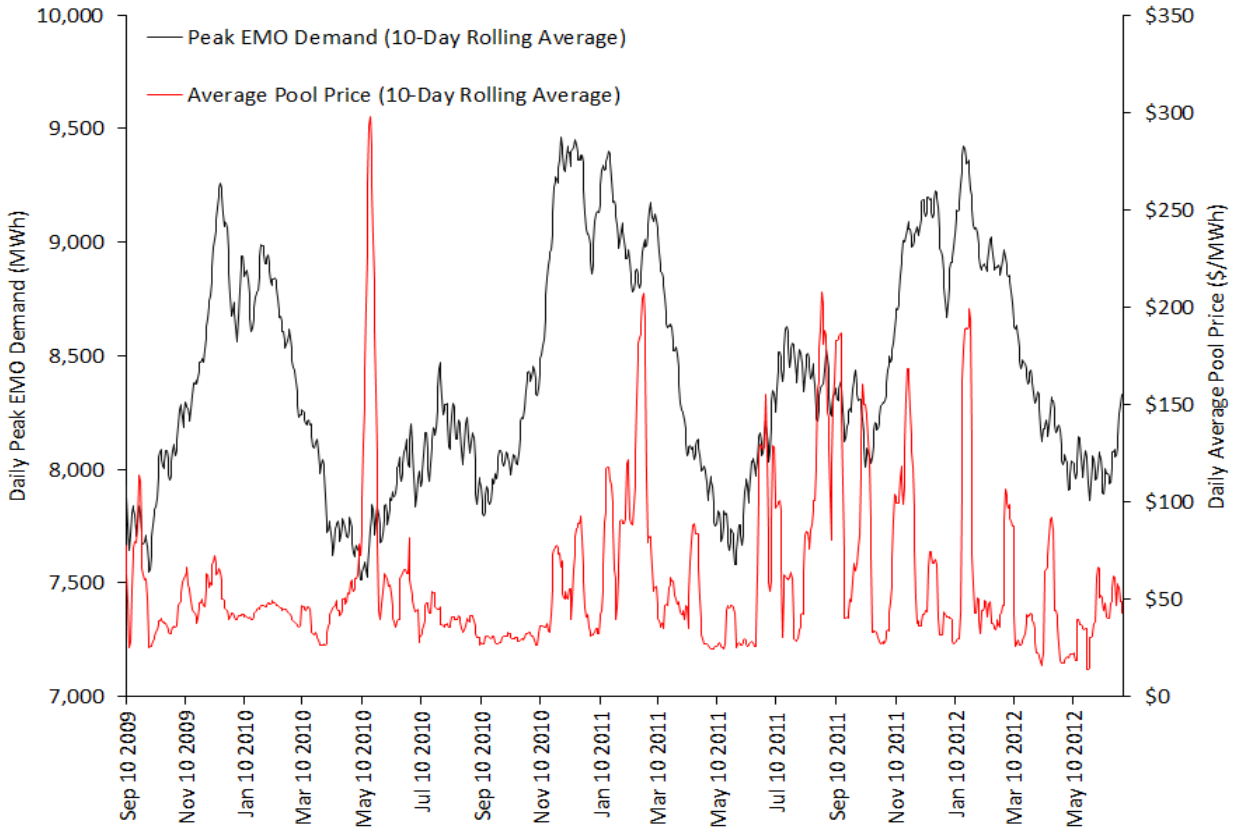
Figure 36: A scatterplot of Pool Prices against hourly demand in the Energy Merit Order



As highlighted above, in the vast majority of hours, the price for electricity in Alberta is relatively low. In the sample period, pool prices were less than $100 for 92% of the hours. The implication here is that, for the vast majority of hours, the market is relatively competitive and in these hours market demand is a principal factor in determining price. However, the distribution of prices discussed above also shows that a large amount of the value in the electricity market price occurs in the remaining hours. In particular, hours in which pool prices were greater than $100 account for $31, or 52%, of the average pool price across the sample period. The scatterplot and correlation coefficients shown above imply that market demand alone is a weak instrument for explaining the variations in price during these hours. Because these hours are principal drivers of average prices, the overall correlation between hourly market demand and price is also fairly weak (0.26). To see this, Figure 37 illustrates how the peak daily market demand and the daily average price have varied across the sample period. From the Figure it is

apparent that while some price spikes are driven by increases in demand, the daily average prices are often elevated when prevailing demand is relatively low.

Figure 37: Daily Average Pool Prices and Peak Energy Merit Order demand over the sample period



As discussed in section 3.3, coal and gas-fired generation currently account for 84% of Alberta's generation capacity. Therefore, the prevailing marginal costs of Alberta's thermal generation can be expected to have important implications for prices when the market is competitive. While coal-fired capacity alone covers 44% of Alberta's capacity, almost all of the coal units in Alberta have "mine-to-mouth" operations, meaning that the coal to feed each plant is directly located adjacent to the power plant. Also because of the formulation of Alberta's coal there is little demand for Alberta's coal resources outside of these operations. Therefore, the marginal costs of coal generation in Alberta are relatively stable and are predominantly determined by long-term

contractual agreements with the mine, labour and diesel costs, and by prevailing environmental regulations.

In contrast, there is a deep and liquid market for natural gas in Alberta and the opportunity cost of burning natural gas to generate electricity is quite variable. Since gas-fired generation accounts for over 40% of Alberta's generation capacity, the prevailing price of natural gas is an important input-cost for Alberta's electricity market. Therefore we should expect to see a reasonably high level of correlation between the price of natural gas and the price of electricity in Alberta.

Figure 38: There was relatively little correlation between Pool Prices and Gas Prices in the sample period

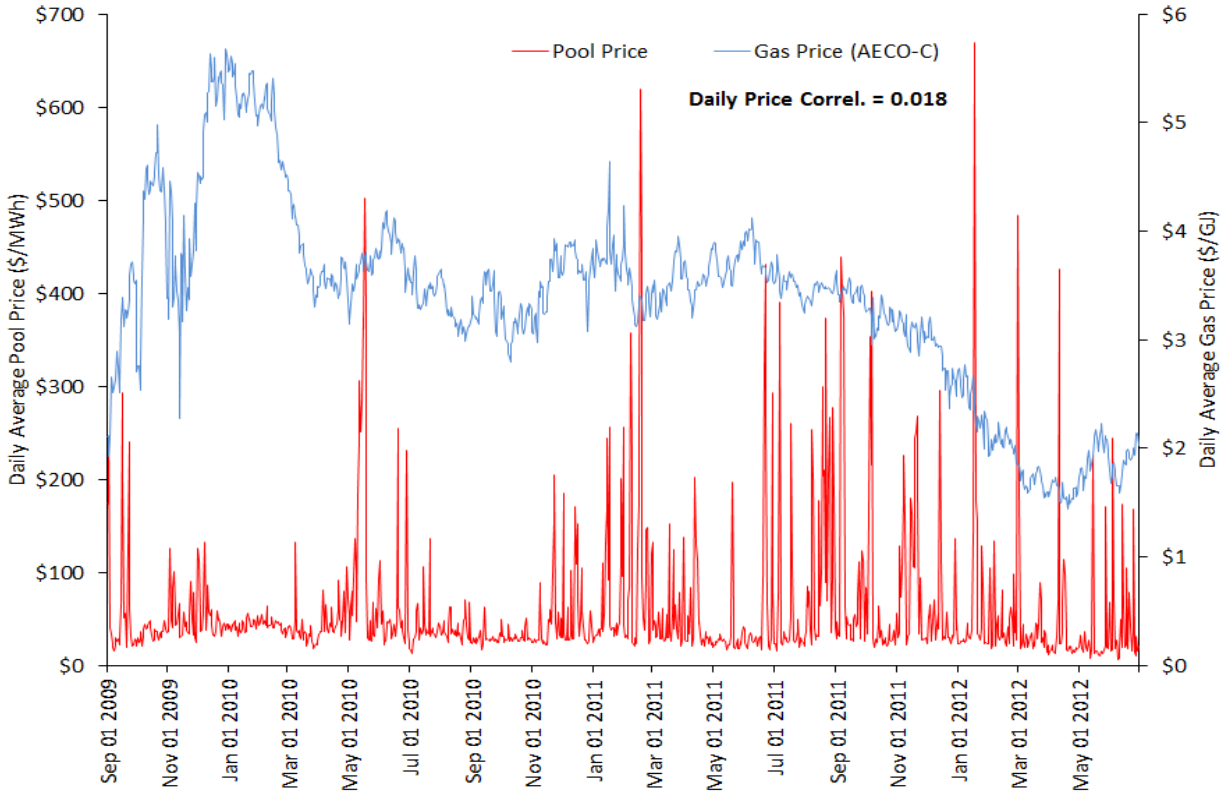


Figure 38 illustrates how the daily average pool price and the daily price of natural-gas[65] varied across the sample period - with the price of natural gas being shown by the axis on the right-hand side. The Figure illustrates that daily electricity prices were highly volatile in comparison with the daily price of natural gas. For example, the average daily price of natural gas ranged from $1.4 to $5.7/GJ and averaged $3.4/GJ over the sample period, while the daily average pool price ranged from $5.6 to $670/MWh and averaged $60/MWh. As a result, the correlation coefficient between the two prices was 0.018, indicating a very weak level of correlation between the daily average prices.

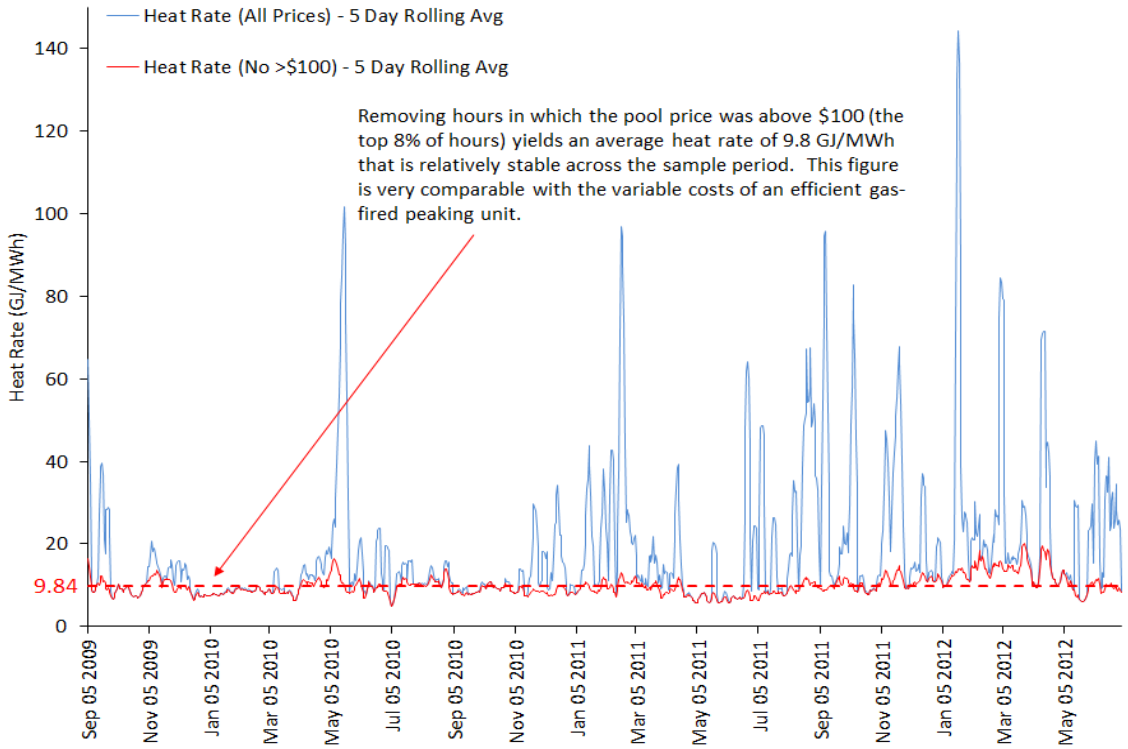
However, recall that the daily average price of electricity is often driven predominantly by the high prices realized in relatively few hours. Once these hours are removed from the sample, a much stronger relationship between gas and electricity prices in Alberta can be established. Using simple correlation coefficients, the correlation between the daily average price of electricity and the daily average price of natural gas increases from 0.018 to 0.53 once hours in which pool prices were greater than $100 are removed from the data.

The extent of this is illustrated by Figure 39. This blue line on the Figure shows how the daily market heat rate varied over the sample period. The prevailing market heat rate is obtained by dividing the price of electricity by the price of natural gas to yield the implied number of gigajoules that were required to produce one megawatt-hour of electricity. The heat rate of gas fired units generally ranges from 6 – 10 GJ/MWh depending upon the unit's configuration; (i.e. whether the units is co-generation, combined-cycle, or a single combustion turbine) the heat rate

[65] The price of natural gas used is the daily weighted average at the AECO-C hub. No price is listed on weekends or on statutory holidays, on these days the daily value is set equal to the traded price on the previous business day – normally Friday's price.

of a single combustion turbine (or 'peaking') gas unit is normally at the upper end of this range, around 8 – 10 GJ/MWh.

Figure 39: The Alberta market Heat Rate is heavily influenced by a few hours when electricity prices are high



As shown by Figure 39, the daily Alberta market heat rate was highly volatile over the sample period as electricity prices occasionally spiked independently of prevailing natural gas prices. However, by removing the hours in which pool prices were greater than $100/MWh the market heat rate is shown to be much more stable around an average heat rate of 9.84 GJ/MWh. This illustrates that, in the vast majority of hours, the prevailing natural gas price is an important factor in determining power prices in Alberta. This, in turn, implies that the electricity market was relatively competitive in these hours. However, since the price of electricity outside of these hours is often highly influential in determining the prevailing average price of electricity, gas

prices are shown to be substantially less relevant when analyzing Alberta electricity prices from a broader perspective.

6.3.3 Pool Prices and Structural Market Power

Previous sections of this chapter have established that generator market power and pool prices in the Alberta market are both variables with distributions that are significantly skewed to the right. That is, generator market power and pool prices are both relatively low for the vast majority of hours and occasionally these variables spike to abnormally high levels. The analysis in this section highlights that structural market power and the resulting pool prices are variables which are highly correlated with one another. The implication here is that the hours in which market prices are abnormally high are also the hours in which generators in the Alberta market have the greatest ability to influence market prices.

Figure 40 shown below illustrates the relationship between the hourly pool price and the 'market' inverse adjusted RSI metric. This structural market power measure illustrates the extent to which the priced generation of the largest supplier, in that hour, is pivotal to the clearing of the Energy Market. As shown, pool prices tend to be relatively low when the market inverse adjusted RSI is below 0.95. As the largest generator in the Energy Market becomes increasingly pivotal, the resulting pool prices illustrate a greater amount of variation and tend to be higher.

Figure 40: The relationship between the hourly Pool Price and the hourly 'Market' Adjusted RSI[66]

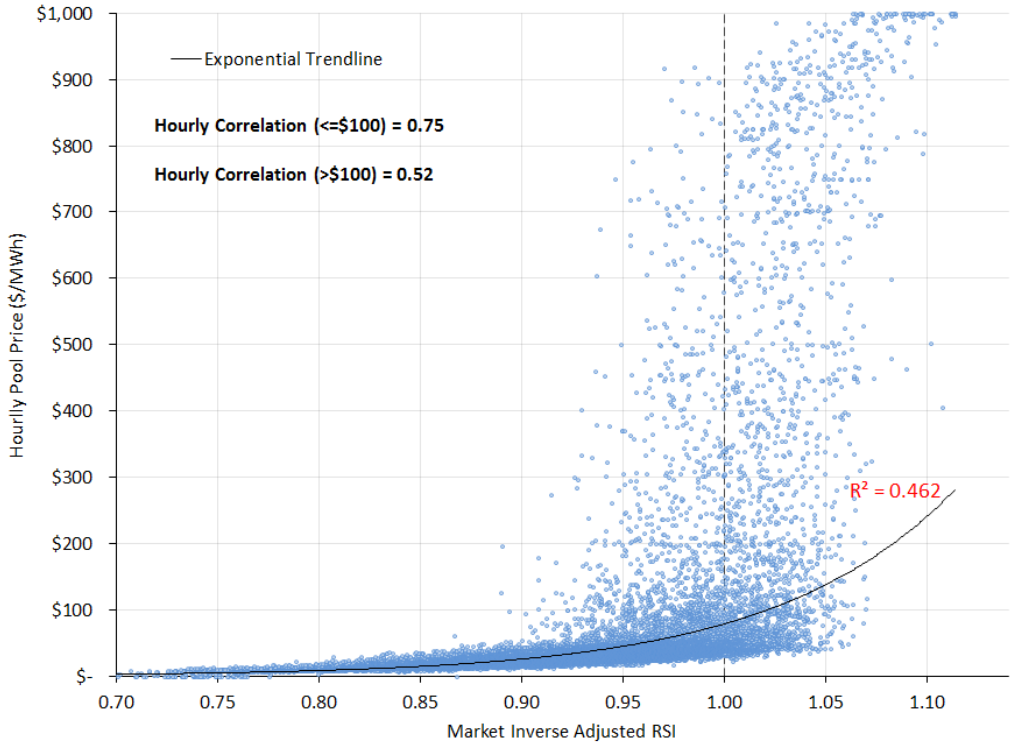


Figure 40 also shows that, in contrast with market demand and prevailing gas prices, the adjusted RSI measure is reasonably correlated with higher pool price values. For example, in hours when pool prices are greater than $100, the correlation between price and the adjusted RSI metric is 0.52. This result is corroborated by Figure 41 which plots the daily average pool price against the daily average market inverse adjusted RSI. As shown, the daily average adjusted RSI metric is useful in explaining variations in the daily average pool price, which in turn are often driven by a few high priced hours.

The correlation between structural market power and the resulting pool prices is unsurprising and does not mean that the strategic behaviour of Alberta's largest generators is the root cause of all high-prices. In particular, shortfalls in supply caused by unit outages, reduced wind generation,

[66] The Market Adjusted RSI is the Adjusted RSI of the largest generator in that hour.

or transmission issues will increase both pool prices and the extent to which the larger generators in Alberta are pivotal to the Energy Market. Therefore, analyzing the simple correlation between these two variables cannot be used to quantify the extent to which one causes the other.

Figure 41: The Daily Average Pool Price and the Daily Average 'Market' Adjusted RSI

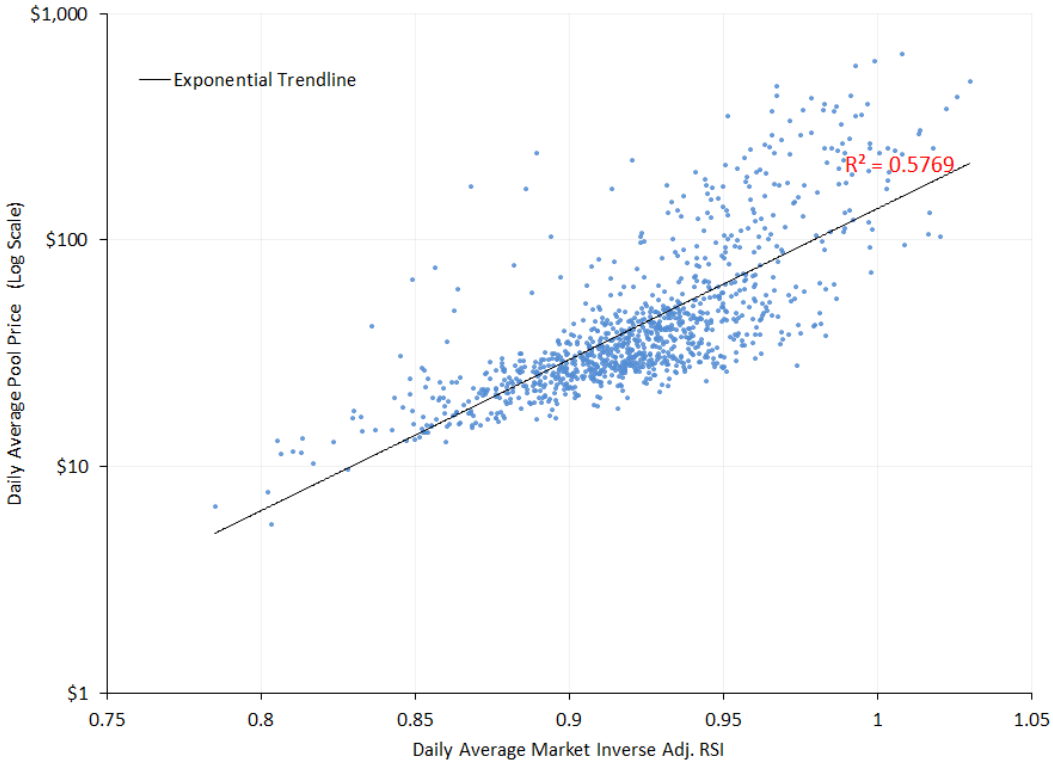


Figure 42 illustrates the relationship between the average inverse semi-elasticity of ENMAX's residual demand function and the monthly average pool price. Likewise, Figure 43 illustrates how the pool price and the ability of Capital Power to influence market prices varied over the sample period. As highlighted above, the average value of a firm's residual demand measure is often driven by the firm having a significant amount of market power in a few peak hours. Both Figures illustrate a strong degree of correlation between the structural measure of market power and the resulting pool prices. In particular, both Figures illustrate that spikes in the larger firms' ability to influence market prices are often accompanied by price increases.

Again, it is important to highlight here that this correlation does not establish causation. In a competitive market, a scarcity in supply relative to the prevailing market demand will cause prices to increase as higher-cost units are dispatched. This increase in market tightness will also tend to shift the market equilibrium onto a steeper portion of the supply function, where the concentration of competing generation is often sparse. In this region of the market supply, the residual demand functions of the larger suppliers will tend to be steeper, meaning that firms are more able to influence the market price through offer changes. In this way, generators have the ability to intensify the resulting price rise by pricing up their capacity when the market is tight, and such a strategy can be highly profitable for a firm selling heavily into the resulting market price. To analyze the extent to which firms do indeed alter their offer behaviour in response to changing market fundamentals requires econometric analysis which controls for changes to a firm's marginal costs. This econometric analysis is undertaken for Alberta's two largest generators, ENMAX and TransCanada, in section 6.3.

Figure 42: ENMAX's Monthly Average Residual Demand estimates and Monthly Average Pool Prices

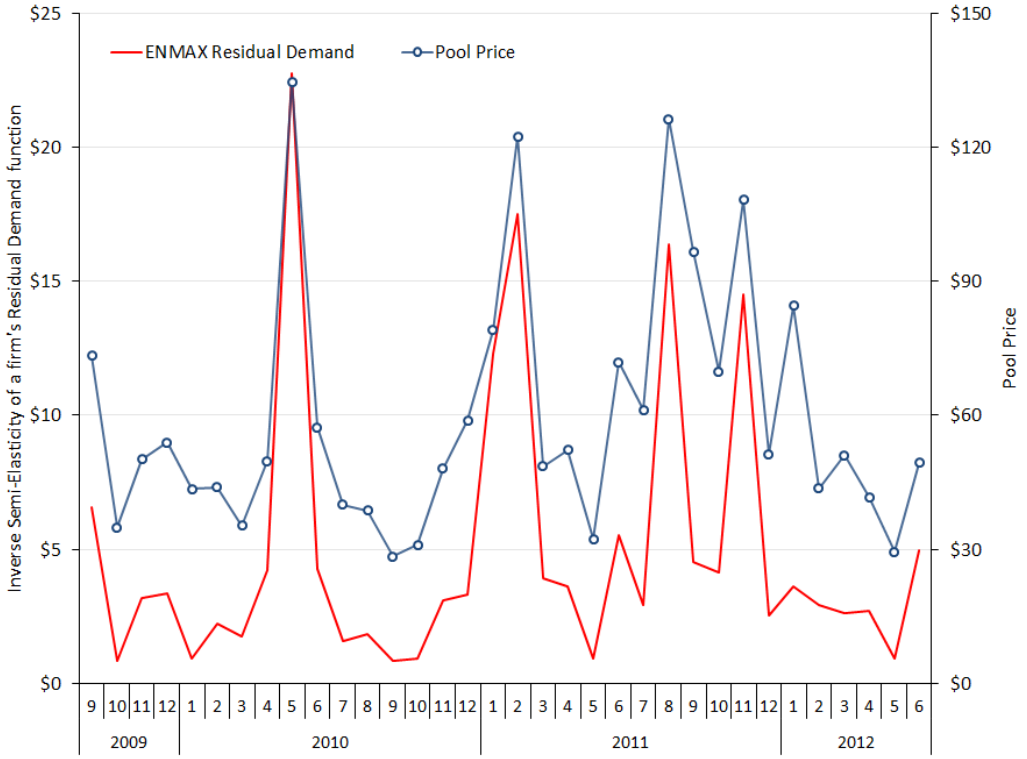
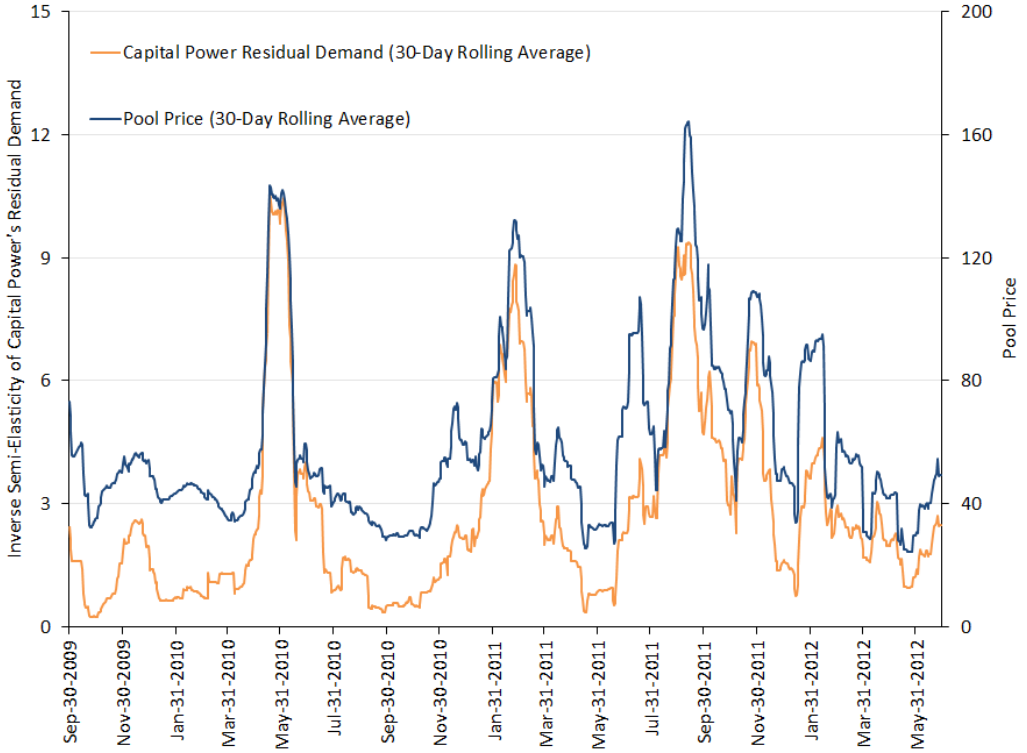


Figure 43: Capital Power's Residual Demand estimates and Pool Prices over time



6.3 Structural Market Power and Supplier Offer Behaviour

As highlighted in section 5.3, the incentives a firm has to exercise market power will depend upon the firm's overall portfolio position, or its exposure to the hourly pool price. Exercising market power to increase price will only be a profitable strategy if the generating company is selling into that market price. Indeed, a generating company that is actually buying from the market may optimally exercise market power in order lower prices by running its generation when prices are below marginal cost.

Consequently, we should expect to see that firms which are less exposed to the hourly pool price to be less aggressive in terms of exercising market power to increase price. This section of the thesis compares and contrasts the offer behaviour of the two largest generators in Alberta - TransCanada and ENMAX. As shown in previous sections, these two companies are the largest generators in Alberta and often have similar levels of structural market power across the sample period; however, in terms of their overall portfolio these companies are considerably different.

6.3.1 ENMAX – Background and Quantitative Analysis

ENMAX Corporation is owned by the City of Calgary and consists of two subsidiaries, ENMAX Power and ENMAX Energy Corporation. Through ENMAX Energy, ENMAX competes in the Alberta power pool as a vertically-integrated 'gentailer'. As well as its generation portfolio, ENMAX Energy has a large presence in the Alberta retail electricity market. Many of these retail sales are sold to consumers for a fixed-price. For example, ENMAX sells power to residential consumers with its EasyMax product advertising power for a price of $89/MWh. While this price may be based on ENMAX's broad view of future market outcomes, the retail price for these sales does not vary with the hourly pool price, so ENMAX is effectively buying

this electricity from the wholesale market at pool price, reducing the firm's exposure.[67] Therefore, ENMAX's retail sales will cause the firm to optimally be less aggressive in exercising market power to increase price when the firm has the ability.

It is perhaps important to emphasize that vertically integrated utilities are not uncommon in deregulated electricity markets – for instance, electricity markets in New Zealand and Australia both have a large degree of vertical integration. The principal rationale for vertical integration is to reduce the risks associated with wholesale price volatility and investing in new generation capacity. By locking in a margin above its generation costs the firm is able provide greater certainty regarding the future profitability of its assets. This in turn reduces the risk of new investments, which allows the firm to develop generation capacity with a lower cost of capital.

Table 11 shows the assets that ENMAX has in the Alberta wholesale market. In total the capacity of these units sums to over 2,160 MW. However ENMAX does not have offer control over its wind facilities and the excess energy / increased capacity its PPA units is controlled by the PPA Owner. In its recent offer control survey the MSA estimates that ENMAX controls 1,830 MW of capacity.

[67] See ENMAX (2012) Financial Report

Table 11: ENMAX's Alberta generation portfolio

Asset Name	Fuel Type	Capacity (MW)	Ownership Type
Keephills #1 Keephills #2	Coal	406 400	PPA Buyer
Battle River #1 Battle River #2 Battle River #3	Coal	149 155 389	PPA Buyer
Calgary Energy Centre (Calpine)	Natural Gas (Combined Cycle)	300	Purchased from Kelson Canada in 2008
Crossfield #1 Crossfield #2 Crossfield #3	Natural Gas	48 48 48	Owner and operator
ENMAX Taber	Wind	81	Owner and operator
Kettles Hill	Wind	63	Owner and operator
McBride Lake	Wind	75	50% with TransAlta

To analyze how the offer behaviour of ENMAX changes as its ability to influence the market varies, I analyze the marginal offer price on a unit-specific basis. The marginal offer price is defined as the highest offer price on a unit that is dispatched. A simple way to illustrate the comparison between the marginal offer price and a firm's market power is to plot a unit's marginal offer price and the firm's Adjusted RSI as rolling averages. This simple comparison is used to provide a gauge of the numbers involved and some overall intuition for the approach. To determine the extent to which a firm's structural market power alters its offer behaviour requires thoughtful econometric analysis. This analysis is done in section 6.3.3.

Figure 44 shows how the marginal offer prices on ENMAX's coal-fired PPA assets changed as the firm's ability to exercise market power varied over the sample period. The measure of market power used here is the Inverse Adjusted RSI measure; increased values of this metric imply a greater ability to exercise market power. As shown by the Figure, the offer behaviour on

ENMAX's coal units is relatively constant and does not change as the firm's ability to exercise market power varies. The Keephills assets are generally dispatched around $15 while the Battle River units are typically dispatched around $25.

Figure 44: The Max. Daily Values of ENMAX's Market Power and the Marginal Offer Price on its coal units

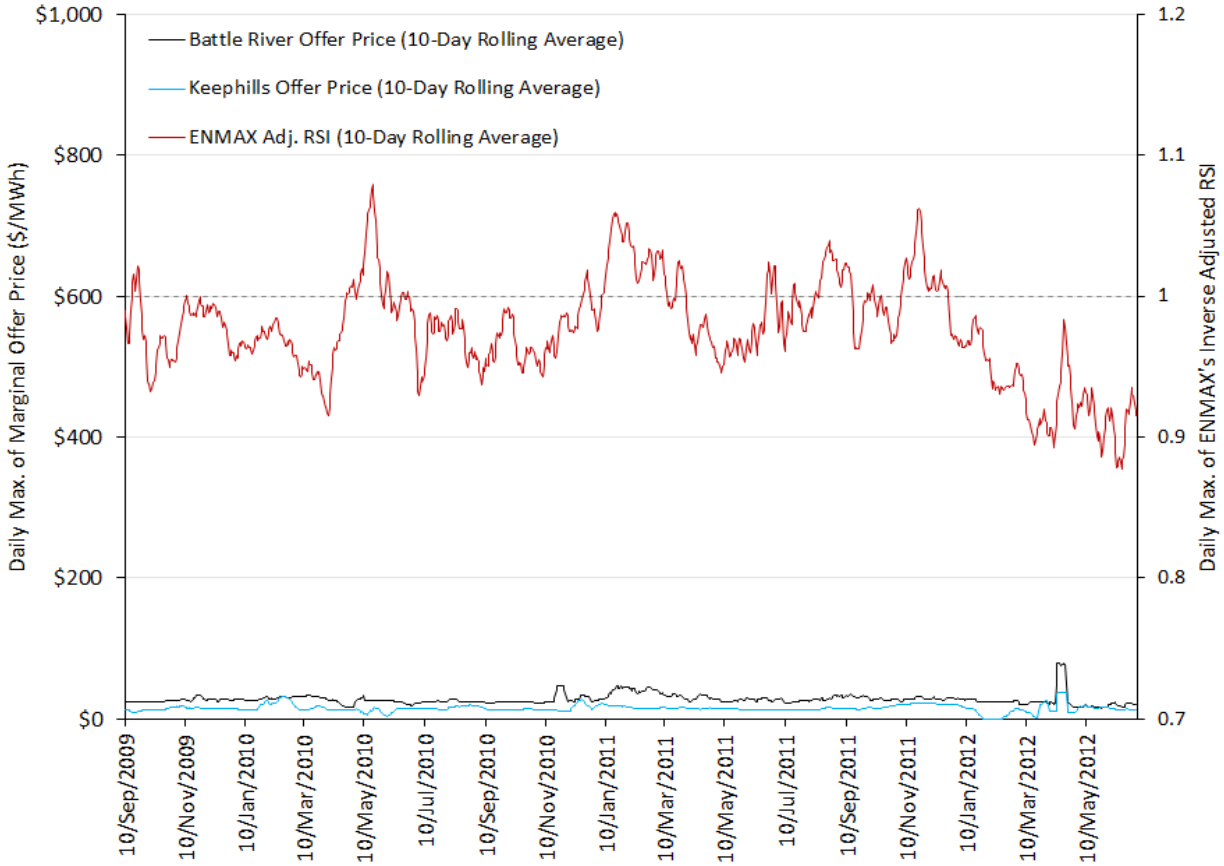


Figure 45 provides the same analysis for ENMAX's gas-fired units. The major determinant of marginal cost for gas-fired generators is the prevailing price of natural gas. To account for changes in the daily gas price, the Figure illustrates the marginal offered heat rate on ENMAX's gas units. A unit's marginal heat rate is calculated as the unit's marginal offer price divided by the cost of natural gas.[68] A unit's heat rate value will vary depending on prevailing temperatures and the unit's current output level. An additional physical characteristic of note is that

[68] The natural gas price used is the maximum daily price of natural gas traded at the AECO-C hub.

ENMAX's Calpine unit has duct-firing capacity to take the unit's generation levels above 250 MWh to a maximum of 300 MWh. This duct-firing generation is likely to be of higher cost in comparison with the generic portion of the combined-cycle unit.

Figure 45: ENMAX's market power and the dispatched Heat Rates on its Gas Assets

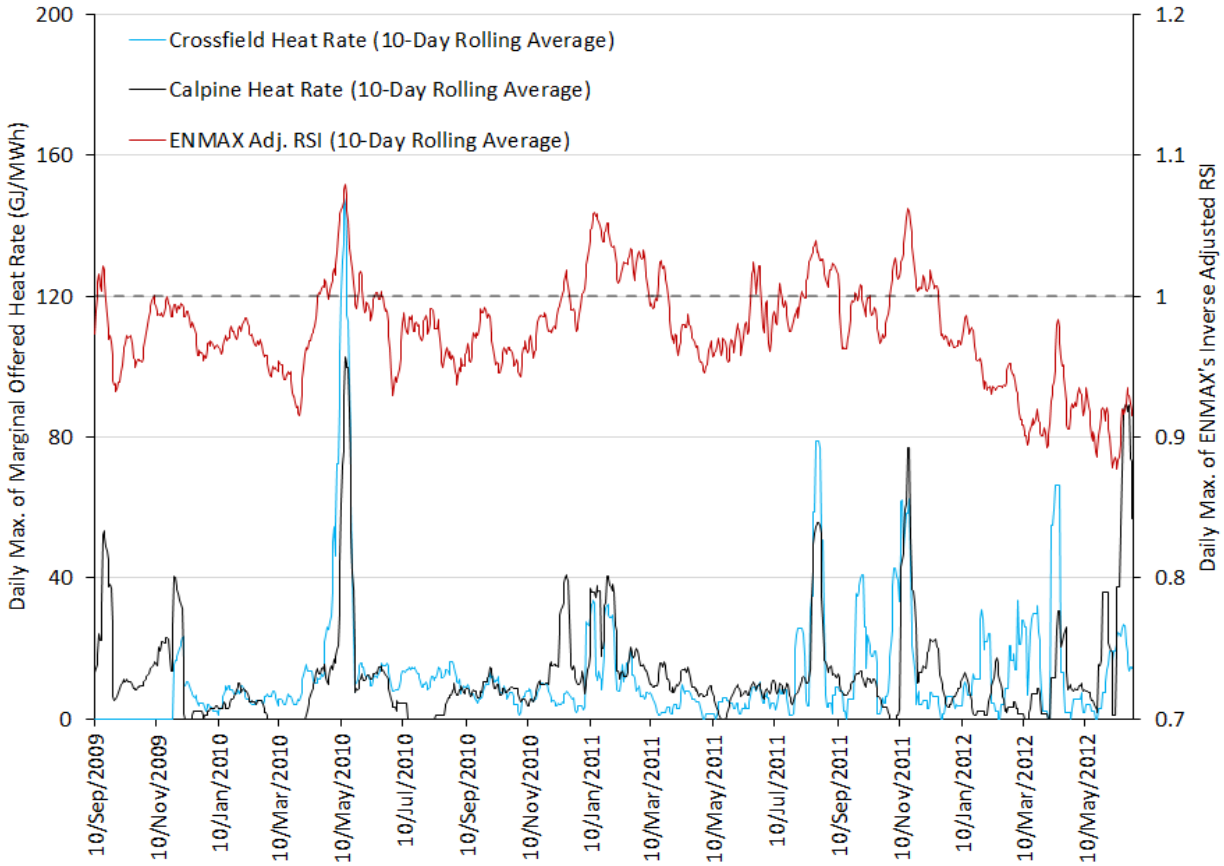


Figure 45 highlights that ENMAX's offer behaviour on its gas plants is variable in comparison to the offer strategies employed on its coal-fired generation. The implication here is that ENMAX uses its coal-fired generation to meet the bulk of its retail market obligations and generally offers these units in at marginal cost. On the other hand, ENMAX's gas-fired assets appear to be used either to cover for peaking levels of retail sales or to exercise market power.

Which of these offer strategies is optimally employed will depend upon the firm's prevailing corporate position, which in turn may be a function of the supply and demand fundamentals. When ENMAX's market power is driven by high market demand, it is likely that ENMAX's fixed-price retail obligations will also be high and ENMAX's ability to influence the market may optimally be ignored in this case, as the firm is relatively short to the pool price. In contrast, when ENMAX's market power is driven by a fall in the supply of competing generation, ENMAX is more likely to be relatively long to the market price. In these cases, ENMAX may respond by pricing up its gas units and utilizing its ability to exercise market power.

6.3.2 TransCanada – Background and Quantitative Analysis

TransCanada is a large corporation involved in natural gas and oil pipelines, natural gas storage, as well as power generation. TransCanada's activity in electricity markets is dominated by their assets in Alberta, Ontario and in the Northeast of the US. Within Alberta, TransCanada is the largest generator in the wholesale market, controlling around 2,500 MW of capacity.

As a pipelines operator, TransCanada is arguably a vertically integrated company since the operation of its oil and gas pipelines in Alberta requires buying power from the Alberta power pool. However, TransCanada's pipelines operate in a regulated market where tariffs are set based on the costs of the operations, so the electricity costs are effectively 'flowed through' to pipeline users and the pipelines sector of TransCanada faces little exposure to wholesale electricity prices.[69]

In comparison with ENMAX, a larger proportion of TransCanada's generation capacity is merchant capacity that is either sold through forward financial contracts or into the real-time

[69] See Alberta MSA report on 'Identification of Impediments to Forward Contracting'.

wholesale market.[70] The exceptions here are TransCanada's cogeneration facilities. Many of TransCanada's cogeneration assets in Alberta have been built primarily to service the demands of an on-site host. At these facilities, TransCanada often has long-term bilateral contracts to supply power (see Table 12).

To keep things relatively straightforward, my analysis of TransCanada will focus on the company's coal-fired capacity at Sundance and Sheerness and will not look at the company's cogeneration units. This is done so for a number of reasons. Firstly, the costs at TransCanada's coal-fired facilities are relatively constant because this energy is supplied to TransCanada through long-term PPA contracts. Therefore, the operations at TransCanada's coal facilities are relatively straightforward and these generators are in many ways comparable with the coal-fired assets that ENMAX controls through similar arrangements. In contrast, the operations and costs associated the company's cogeneration facilities are more complex and will likely change as the operational requirements of the on-site host varies. As a result, an extreme offer price at a cogeneration facility could be reflective of opportunity costs or operational requirements of the on-site host.

[70] TransCanada's financial reports often provide percentage hedge levels for its Alberta power assets.

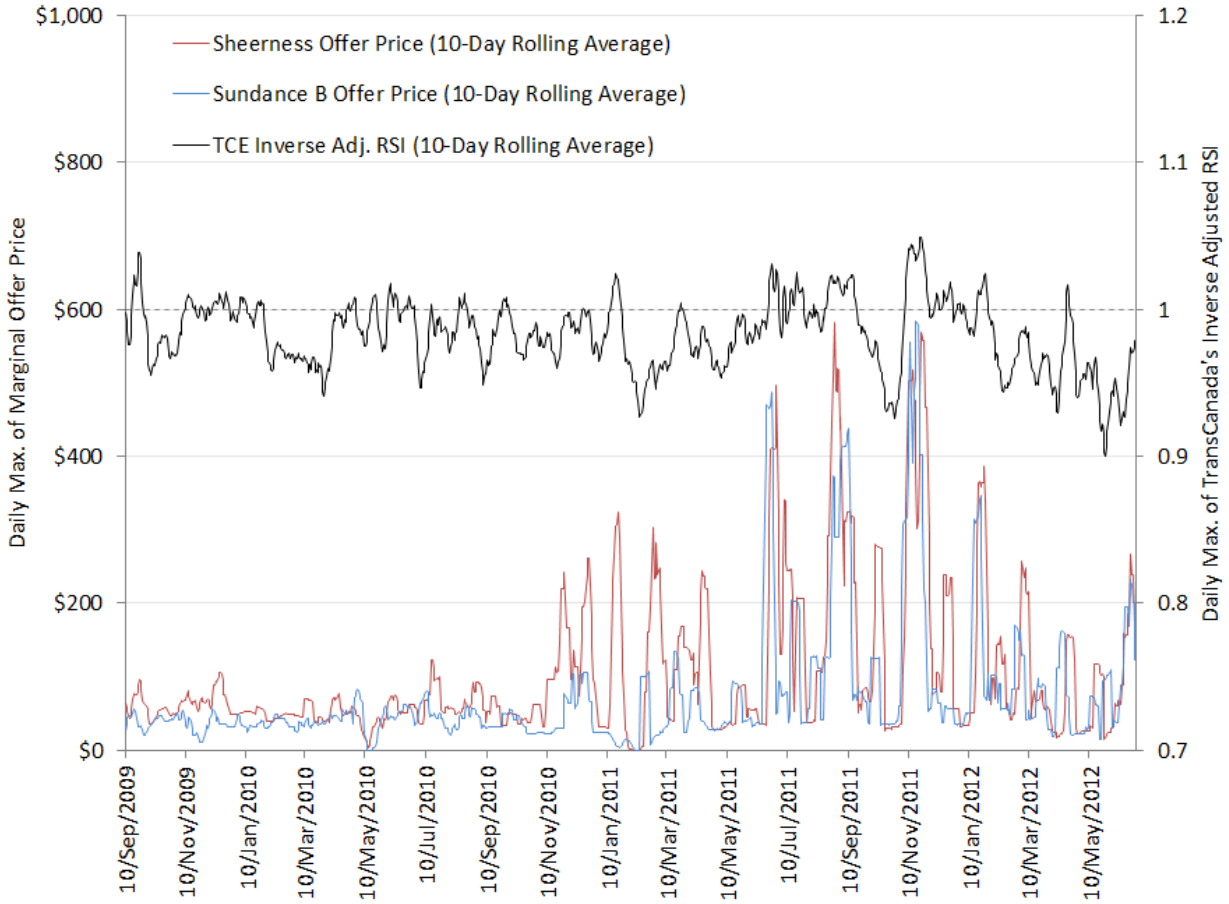
Table 12: TransCanada's generation portfolio in Alberta

Asset	Fuel Type	Capacity (MW)	Ownership Type
Sheerness #1 Sheerness #2	Coal	390 390	PPA Buyer
Sundance #1 Sundance #2	Coal	288 288	PPA Buyer
Sundance #3 Sundance #4	Coal	362 406	PPA Buyer
MacKay River	Natural Gas (Cogeneration)	185	Owner and operator – includes long-term contracts with Suncor
Bear Creek #1 and #2	Natural Gas and Waste Heat	58 36	Owner and operator – includes long-term contracts with Weyerhauser
Carseland	Natural Gas (Cogeneration)	95	Owner and operator – includes long-term contracts with Agrium
Redwater	Natural Gas (Cogeneration)	46	Owner and operator – includes long-term contracts with Williams Energy
Cancarb	Waste Heat and Natural Gas	42	Owner and operator – a primary customer is the City of Medicine Hat

Figure 46 illustrates how the maximum daily marginal offer price on TransCanada's Sheerness and Sundance B (Sundance #3 and #4) assets varied as the company's ability to exercise market power changed over the sample period. As shown, TransCanada often increases the offer prices on these units when the firm has the ability to exercise market power. For instance, the 10-day moving average for both Sheerness and Sundance B peaked to over $550 in November 2011 as these generators were dispatched at high offer prices. As shown by the Inverse Adjusted RSI, TransCanada's ability to exercise market power at this time was high as the metric peaked to around 1.05. These illustrations are in contrast with the same analysis for ENMAX's coal fired generators, where the offer prices were shown to be relatively constant.

In addition, the offer behaviour of TransCanada shows a distinct change towards the end of 2010. Both Sheerness and Sundance B illustrate that TransCanada's offer strategies were more variable and responsive to the company's ability to exercise market power in the latter half of the sample period.

Figure 46: TransCanada's market power and the dispatched offer prices on Sheerness and Sun. B



6.3.3 Econometric Analysis: Setup

To analyze the extent to which a firm alters it offer behaviour in response to changes in its ability to exercise market power requires econometric analysis. In particular, the econometric analysis is used to establish causation, i.e. does a change in the firm's ability to exercise market power cause the firm to alter its offer strategy? Fundamentally, this econometric analysis must

distinguish between changes in the marginal offer price that are implemented to exercise market power from the offer changes that are the result of changes to variable costs.

At a company level, a firm's marginal costs can vary both across generating facilities and within generating facilities. For example, ENMAX's marginal costs may change as the company's marginal generation changes from Keephills #1 at 300MW to Keephills #1 at 360MW. In addition, the marginal costs may change as the marginal generation changes from Keephills #1 at 300MW to Crossfield #2 at 40MW. To control for cost changes adequately requires controlling for both of these variations. To ensure that this is the case, the thesis undertakes a separate econometric analysis for each generation facility.

For ENMAX, the facilities examined are Keephills, Battle River, Crossfield and Calpine. For TransCanada the facilities analyzed are Sheerness, Sundance A and Sundance B. Note that there is usually more than one generating unit at each of these facilities. For example, the Sheerness facility consists of two generating assets. However, the operations and the cost structures of the generators at these facilities are sufficiently uniform to prevent an individual unit-by-unit analysis from being warranted.

For coal-fired generation, the econometric equations estimated are as follows:

$$Offer\ Price_{UHDM} = \beta_0 + \beta_1 MP_{JHDM} + \beta_2 From_{UHDM} + \beta_3 To_{UHDM} + Month + Hour$$

Where:

$Offer\ Price_{UHDM}$ is the marginal offer price (i.e. the highest priced block that is dispatched) on unit U in hour H on day D in month-of-the-sample M.

β_0 is the intercept term.

MP_{JHDM} is the market power metric for firm J in hour h on day D in month-of-the-sample M. The three market power metrics used are discussed below.

$From_{UHDM}$ and To_{UHDM} show where in the units production curve the marginal block is dispatching 'from' and 'to'. For example, a unit may be dispatched a block 'from' 100 MWh 'to' 120 MWh.

$Month$ are month-of-the-sample M fixed effects.

$Hour$ are hourly fixed effects.

For gas-fired assets, the econometric equations are estimated as follows:

$$Offer\ Price_{UHDM} = \beta_0 + \beta_1 MP_{JHDM} + \beta_2 From_{UHDM} + \beta_3 To_{UHDM} + \beta_4 Temp_{HDM} + \beta_5 Temp^2{}_{HDM} + AECO_C_{DM} + Month + Hour$$

Where:

$Offer\ Price_{UHDM}$ is the marginal offer price (i.e. the highest priced block that is dispatched) offered by unit U in hour H on day D in month-of-the-sample M.

$Temp_{HDM}$ is the average hourly temperature in hour H on day D in month-of-the-sample M.

$Temp^2{}_{HDM}$ is the average hourly temperature squared.

$AECO_C_{DM}$ is the maximum daily price of natural gas that was traded at the AECO-C hub on day D in month-of-the-sample M.

And the remaining terms are consistent with those defined in the previous equation.

Using this econometric approach, the major factors that affect the marginal costs of thermal generating units are accounted for. Therefore, the β_1 parameter can be interpreted as the impact

of an increase in the firm's ability to exercise market power on the marginal offer price, holding changes in marginal costs constant.

The coal facilities analyzed here are all assets which the firm has offer control of via Power Purchase Arrangements. Under these contracts, the assets' marginal costs are primarily a function of a series of economic indexes and will also depend upon where the assets are in their production curves. To control for the latter of these, the 'from' and 'to' variables are included. The majority of the indexes used to calculate costs within the PPAs are monthly, so variations in these indexes are captured by the month-of-the-sample fixed effects. In addition, the hourly fixed-effects were included to allow the operational characteristics of the units to vary systematically within days of the sample. As well, the hourly fixed effects will pick up market effects, such as system ramping, which will vary across hours of the day and may not captured by the market power metrics.[71]

For the gas-fired facilities the econometric approach is similar although a couple of changes are made to account for additional factors. The primary input cost to control for at gas-fired facilities is the cost of natural gas.[72] To reflect this, a daily index of local natural gas prices is included as an independent variable. Again, the 'from' and 'to' variables are included to account for variations in marginal costs across the production curve. The monthly fixed effects are included to account for long-term changes, such as inflation rates and labour costs, while the hourly fixed effects are included for the same reasons outlined above. In addition, variations in

[71] The market power measures are calculated using hourly-snapshot data which provides the prevailing market fundamentals mid-way through the hour.

[72] Even for units that have procured gas via a long-term fixed-price contract, the daily trading prices of natural gas represent the opportunity cost of burning the natural gas to generate electricity.

the local hourly temperatures are included for gas-fired units to account for the effect that prevailing temperatures may have on the units' heat rate.

Market Power Measures for Econometric Analysis

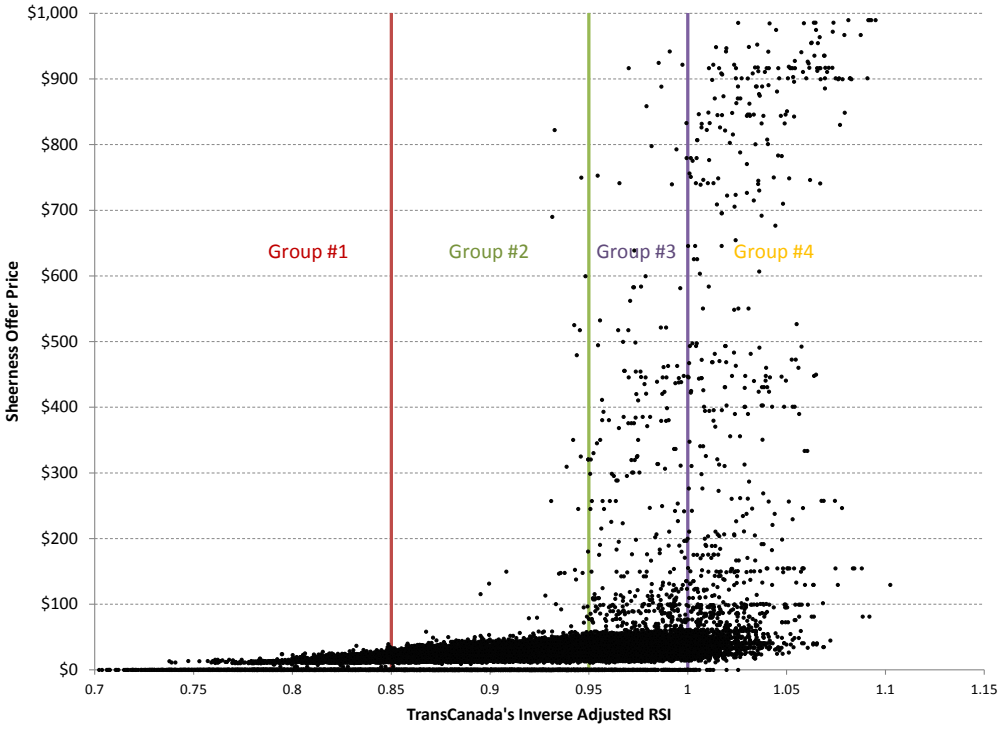
From the two market power metrics developed in chapter 5, the thesis utilizes three measures of a firm's ability to exercise market power which are to be used in the econometric analysis. The first two market power measures are consistent with the two measures developed in chapter 5; the Inverse Adjusted RSI metric and the Semi-elasticity of a firm's inverse residual demand function. The third market power metric used here is a 'dummy variables' version of the Inverse Adjusted RSI metric, which effectively splits the Inverse Adjusted RSI metric into four groups:

Table 13: The Adjusted RSI grouped analysis

Adjusted RSI Group #	Lower Bound: Inverse Adjusted RSI Value (>=)	Upper Bound: Inverse Adjusted RSI Value (<)
1	-	0.85
2	0.85	0.95
3	0.95	1.00
4	1.00	-

One justification for this approach is that the effect of the Inverse adjusted RSI metric on offer prices is often not linear. As an example of this, Figure 47 illustrates a simple scatterplot of the Sheerness marginal offer price against the Inverse Adjusted RSI of TransCanada for the entire sample period.

Figure 47: TransCanada's market power and the marginal offer price on Sheerness



As illustrated by Figure 47, the responsiveness of TransCanada's offer price on Sheerness to an increase in the firm's market power is more variable at higher values of the Inverse Adjusted RSI. For instance, an increase in the Inverse Adjusted RSI from 0.75 to 0.85 is unlikely to have the same impact on the firm's offer behaviour as will a 0.1 increase from 1.00 to 1.10. In recognition of this, some researchers (Wolak and McRae (2012) for example) abandon a refined RSI metric in favour of a regression analysis using a simple binary variable to reflect whether or not a firm is pivotal.

The third approach here is a hybrid of these two approaches which splits the Adjusted RSI measures into four groups. It should be noted that other alternative model specifications, such as taking the natural logs and including a squared term, were considered. However, the simple approach depicted by Figure 47 above was shown to be a decent econometric model in comparison, and also has the advantage of being easily understood. While the specific selection

of the group bounds is somewhat arbitrary, the selection of each group does have a considered purpose.

Group 1 (<0.85): The first group is used throughout as a base group. Within this group, the Inverse Adjusted RSI metric implies that the firm is very limited in its ability to exercise market power. As shown by Figure 47 the Sheerness unit is typically dispatched at low market prices within group #1.

Group 2 (>=0.85, <0.95): Within the second group the market participant is typically limited in its ability to exercise market power. Occasionally, the firm may be able to drive the pool price at higher levels of the inverse adjusted RSI within this band. This behaviour is not normal, however, and is likely to be driven by an unusually long exposure to pool price.

Group 3 (>=0.95, <1): In the third group, the inverse adjusted RSI implies that the market participant has a reasonable ability to influence market outcomes. Within this group the ability of the market participant to profit from this ability will likely depend upon the firm's net exposure to pool price, and/or the ability of the firm's employees to forecast the market fundamentals two to three hours ahead of real-time.

Group 4 (>=1): Finally, in the fourth group the Inverse Adjusted RSI metric implies that the firm's priced generation is pivotal to the clearing of the energy market. It is reasonable to expect that the firm will be able to forecast its ability to exercise market power in the many of these hours. Therefore, the extent to which the participant exercises market power in these hours will be highly depend upon the firm's net exposure to pool price. In addition, there are likely a few scarcity outliers in this group in which the firm may rationally conclude that offer changes are

not necessary to increase the market price. These scarcity events are few and far between and thus are unlikely to affect the overall econometric results.

6.3.4 Econometric Analysis: Results

The econometric results for each of the three market power measures are illustrated by unit in Tables 14 - 17. The reported econometric coefficients are to be interpreted as follows:

Within the **Adjusted RSI Analysis** the market power coefficient is to be interpreted as; a 0.1 increase in the firm's Inverse Adjusted RSI metric causes a $ change in the marginal offer price on the relevant unit, holding marginal costs constant. For instance, the $1.09 value on Keephills means that as ENMAX's inverse adjusted RSI increases by 0.1 the marginal offer price at Keephills tends to increase by $1.09. For gas units, the Tables also report the impact of gas price changes on the marginal offer price.

Within the **Residual Demand Analysis** the reported coefficients consider the impact of a $10 increase in the estimated semi-elasticity of the firm's residual demand function on the marginal offer price of a given unit, holding marginal cost constant.

Finally, the econometric results for the **Adjusted RSI – Grouped Analysis** use group #1 as the base group. Consequently, the coefficient on each group is to be interpreted as the unit's marginal offer price within the given group relative to the unit's marginal offer price within the base group, holding marginal costs constant. For example, the arsi_3 coefficient for the Crossfield unit is estimated as $19.70. This coefficient implies that the marginal offer price on ENMAX's Crossfield unit is $20 higher in group #3 than it is in group #1, holding marginal costs constant.

Table 14: Econometric Results for the Adjusted RSI Analysis

Adjusted RSI Analysis

ENMAX Units

Facility	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Keephills	$1.09	0.29	3.81	$0.53	$1.65	0.302	24,623
Battle River	$5.94	0.27	21.80	$5.41	$6.48	0.424	24,753
Crossfield	$47.48	4.32	10.99	$39.01	$55.95	0.263	6,196
CRS AECO-C	$7.50	3.27	2.29	$1.08	$13.91		
Calpine	$21.90	1.67	13.10	$18.63	$25.18	0.264	12,889
CAL AECO-C	$9.78	2.23	4.38	$5.41	$14.16		

TransCanada Units

Facility	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Sheerness	$66.32	3.18	20.87	$60.09	$72.54	0.152	24,687
Sundance B	$33.03	2.22	14.89	$28.68	$37.38	0.139	24,331
Sundance A	$14.08	1.10	12.84	$11.93	$16.24	0.351	11,242

Table 15: Econometric Results for the Residual Demand Analysis

Residual Demand Analysis

ENMAX Units

Facility	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Keephills	$0.13	0.09	1.48	-$0.04	$0.31	0.301	24,623
Battle River	$0.47	0.11	4.23	$0.25	$0.69	0.396	24,753
Crossfield	$0.35	0.07	5.07	$0.21	$0.48	0.255	6,196
CRS AECO-C	$13.76	3.39	4.05	$7.10	$20.41		
Calpine	$0.34	0.06	6.03	$0.23	$0.46	0.292	12,889
CAL AECO-C	$10.77	2.24	4.82	$6.38	$15.15		

TransCanada Units

Facility	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Sheerness	$5.46	0.48	11.43	$4.53	$6.40	0.157	24,687
Sundance B	$2.59	0.33	7.85	$1.94	$3.24	0.131	24,331
Sundance A	$1.95	0.31	6.38	$1.35	$2.55	0.397	11,242

Table 16: The Econometric Results for the Adjusted RSI Grouped Analysis (ENMAX units)

Adjusted RSI - Grouped Analysis

ENMAX Units

Facility / Group #	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Keephills							
arsi_2	$1.14	0.15	7.60	$0.85	$1.44	0.302	24,623
arsi_3	$1.72	0.41	4.15	$0.91	$2.53		
arsi_4	$1.89	0.48	3.93	$0.95	$2.83		
Battle River							
arsi_2	$4.07	0.16	26.16	$3.76	$4.37	0.413	24,753
arsi_3	$6.99	0.36	19.35	$6.28	$7.70		
arsi_4	$11.00	0.58	18.91	$9.86	$12.14		
Crossfield							
arsi_2	$12.92	2.47	5.24	$8.08	$17.75	0.245	6,196
arsi_3	$19.70	3.30	5.96	$13.23	$26.17		
arsi_4	$50.82	5.77	8.80	$39.50	$62.14		
AECO-C	$11.39	3.45	3.30	$4.63	$18.15		
Calpine							
arsi_2	$1.79	1.14	1.57	-$0.45	$4.04	0.272	12,889
arsi_3	$4.28	1.64	2.61	$1.06	$7.50		
arsi_4	$33.18	2.23	14.88	$28.81	$37.55		
AECO-C	$10.70	2.25	4.75	$6.28	$15.11		

Table 17: The Econometric Results for the Adjusted RSI Grouped Analysis (TransCanada units)

TransCanada Units

Facility / Group #	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Sheerness							
arsi_2	-$0.03	0.67	-0.04	-$1.34	$1.28	0.224	24,687
arsi_3	$14.01	1.51	9.27	$11.05	$16.98		
arsi_4	$142.94	6.90	20.71	$129.41	$156.47		
Sundance B							
arsi_2	-$1.60	0.47	-3.44	-$2.51	-$0.69	0.181	24,331
arsi_3	$6.34	1.03	6.16	$4.32	$8.36		
arsi_4	$81.66	5.76	14.18	$70.37	$92.95		
Sundance A							
arsi_2	-$2.13	0.31	-6.92	-$2.74	-$1.53	0.373	11,242
arsi_3	$6.67	0.77	8.67	$5.16	$8.17		
arsi_4	$28.42	3.08	9.23	$22.38	$34.45		

The econometric results obtained support the observations highlighted previously by the quantitative analysis and intuition outlined in section 6.3.3. The pricing on ENMAX's coal assets is shown to be relatively unresponsive to changes in the firm's ability to exercise unilateral market power. The Keephills facility, in particular, is estimated to be the least responsive and has the lowest offer price coefficient of all units within each of the market power measures. The Battle River facility is also shown to be relatively unresponsive to market power changes, although the units at Battle River are shown to be more responsive than the units at Keephills. This result is intuitive since 2 of the 3 units at Battle River are substantially smaller and older than the generators are Keephills, so it is likely that these generators have a higher variable operating cost. A unit that has higher variable costs is cheaper to price-up / dispatch-off because the margin that's foregone is less, so it is unsurprising that the marginal offer price on ENMAX's Battle River units is more responsive than the company's Keephills facility.

Both the 'generic' Adjusted RSI and grouped Adjusted RSI results show that ENMAX's gas units are far more responsive to changes in the firm's ability to exercise market power than the company's coal-fired assets. This result is intuitive since gas-fired units are cheaper to start-up and shut-down, and generally have higher variable costs than coal-fired facilities. Therefore, it is likely optimal for ENMAX to offer its gas units at a higher price, with the risk that they are dispatched-off, and leave its coal fired generators at low prices to ensure they remain in-merit.

In addition, the econometric results show that ENMAX's Crossfield facility is more responsive than the Calpine generator. For example, the marginal offer price on Crossfield is estimated to increase by $47.48 in response to a 0.1 increase in ENMAX's Adjusted RSI whereas the Calpine unit's offer price increases by $21.90. Again, this result is intuitive since Crossfield is a peaking facility that likely has lower start-up costs and higher variable costs than the combined-cycle unit at Calpine.

Table 18: The Econometric Results for the Cloverbar facility
Capital Power's CloverBar Peaking Unit

Adjusted RSI - Grouped Analysis

Group #	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
arsi_2	$13.04	1.70	7.68	$9.71	$16.37	0.302	7,861
arsi_3	$48.82	3.65	13.36	$41.65	$55.98		
arsi_4	$196.48	17.64	11.14	$161.91	$231.06		

Adjusted RSI Analysis

	Coefficient	Robust Standard Error	t-statistic	95% Confidence Intervals		R^2	N
Adj. RSI	$71.86	4.27	16.84	$63.49	$80.22	0.271	7,861

While Crossfield is shown to be relatively responsive to changes in ENMAX's ability to exercise market power, it is important to put these results in context. To do this, Table 18 reports the same econometric estimates for Capital Power's Cloverbar generating facility. The results highlight that Capital Power's offer behaviour on Cloverbar is more responsive to changes in the firm's market power in comparison to ENMAX's Crossfield. For example, the estimated coefficient on Cloverbar's Adj. RSI Group #4 is almost $200, implying that the firm increases its offer price notably when Capital Power's ability to exercise market power is high. In comparison, the same estimate on ENMAX's Crossfield is $50.

This result is not surprising given that ENMAX is a vertically-integrated generator with approximately 180 MW of wind generation. Increases in market demand and decreases in wind generation will both increase the ability of ENMAX to exercise market power. However, both an increase in its retail demand and a decrease in its wind generation will serve to shorten ENMAX's exposure to the pool price and reduce the firm's incentives to exercise market power. In these situations, ENMAX may optimally avoid utilizing its ability to exercise market power. For ENMAX to profitably exercise market power requires that its exposure is relatively long while the firm's ability to exercise market power is also sufficiently high. For a vertically integrated generator this combination will likely require one or both of the following:

- The firm has purchased a relatively large amount of power for a fixed price through the forward financial markets.
- The firm's ability to exercise market power is principally driven by outages / transmission constraints which reduce the ability of competing generators to supply power.

In contrast, 'merchant' generators such as TransCanada do not sell a large amount of power into the Alberta retail market, nor does TransCanada have wind power in its generation portfolio. Consequently, these firms are often 'long' to the Alberta pool price so when these firms have the ability to increase the pool price it is often profitable for them to do so.

This intuition is most evident empirically on TransCanada's Sheerness asset. While these two coal-fired units are likely to have a relatively low variable cost, TransCanada often prices these units up when the firm's ability to influence the market price is high. For example, the econometric results above show that the marginal offer price on Sheerness increases by some $66 when the firm's Adjusted RSI increases by 0.1. This result is higher than any of ENMAX's gas-fired units and is comparable with Capital Power's peaking gas unit at $72. The econometric results also shows that TransCanada's pricing strategies on Sundance A and B were responsive to the firm's ability to exercise market power, although not to the same extent as Sheerness.

This ordering is somewhat surprising given that the four units at Sundance A and B are much older than the two units at Sheerness and will likely have higher variable operating costs. Therefore, from an economic perspective it would make more sense to increase the offer price at Sundance A and B, and take the risk of these units being dispatched-off before the same risk is taken with Sheerness. However these observations may be explained by other factors:

- The Sundance A units were offline for a substantial period of the sample (from December 2010 onwards). In the first half of the sample period, TransCanada appears to have been less aggressive in pricing up its generation units in response to increases in its market power.

- While TransCanada has offer control over the PPA capacity on Sundance B, the PPA was purchased as part of a joint ownership agreement with AltaGas. The commercial arrangements that TransCanada has with AltaGas may increase the costs of exercising market power with these units.

6.4 The Impact of Market Events on Firm Offer Behaviour

The purpose of this section is to highlight the usefulness of the econometrics approach to analyze the impact of market events on generators' offer behaviour. In this section, the thesis uses the Adjusted RSI metric to analyze the impact of the MSA's Offer Behaviour Enforcement Guidelines (OBEGs) on the offer behaviour of larger firms in the Alberta energy market. The impact of the OBEGs on the Alberta market is currently the subject of a number of AUC proceedings surrounding the risks faced by retail companies supplying the Regulated Retail Option.[73] This section begins by providing a brief background discussion of the OBEGs.

6.4.1 The OBEGs: Relevant Background

In 2010 the Alberta Market Surveillance Administrator ('MSA') set out to clarify the broad meaning of its mandate so that market participants could obtain a practical understanding of which strategies and conducts that the market monitor deemed to be inconsistent with the relevant market regulations (notably the FEOC Regulation):

"[The Offer Behaviour Enforcement] guidelines describe the general approach of the MSA in applying the *Fair Efficient and Open Competition Regulation* (FEOC Regulation) to market participant offer behaviour in Alberta's wholesale electricity market." (MSA website)

[73] See AUC Proceeding #2554 in particular.

Within the OBEGs the MSA clarified that the exercise of unilateral market power through economic withholding is not something that, by itself, the market monitor considers to be anticompetitive. In the final guidelines the MSA note:

> "Single participant conduct aimed at capturing surplus (profits) that a market participant has created independent of the conduct's effect on rivals is considered competitive and would not result in enforcement action from the MSA.
>
> In relation to offer behaviour this means market participants are free to pursue individually profit maximizing behaviour that does not impact on rivals' conduct. This would include strategies typically characterized as economic withholding."
>
> See MSA 'OBEGs' (2011)

Since its deregulation Alberta's energy market has never been a 'cost-based' market and generators have never been forced by law to offer their energy at some proxy of variable costs (see Williams (2002) for example). However, the MSA's consultation surrounding the OBEGs was the first time that generators had explicit clarity that the economic withholding of generation was not something that MSA considered to be offside of the prevailing regulations.

Section 6 of the Electric Utilities Act states that '[m]arket participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.' Fundamentally, this is the standard against which any market participant's conduct is to be measured. In 2009 the FEOC Regulation was enacted, and this regulation provided some more guidance as to participant conduct that was considered to be contrary to Section 6 of the EUA. Section 2 of the FEOC Regulation outlines participant conduct that does not support the fair,

efficient and openly competitive operation of the market. Section 2 (j) of the Regulation states that this includes "manipulating market prices, including any price index, away from a competitive market outcome." The FEOC Regulation does not explicitly mention economic withholding or the exercise of unilateral market power.

Prior to the FEOC Regulation, part of the relevant legislation was ISO rule 1.10 'Market Participant Behaviour Guidelines'. Within the 'Undesirable Practices' section of this rule, the ISO noted:

> 'When a market participant in a dominant position exploits its market power in a way that adversely impacts upon the efficient, fair and openly competitive operation of the market, it will be considered an abuse of dominance. Acts which constitute an abuse of dominance include, but are not limited to, the following:
>
> i) […]
>
> ii) economically withholding energy by employing offering strategies so as to adversely impact upon the efficient, fair and openly competitive operation of the market.'
>
> See AESO (2009c) "Comparison Between Existing and Proposed: FEOC Regulation ISO Rules"

Prior to the OBEGs, the MSA highlighted in its 2005 report on 'Undesirable Conduct and Market Power' that an abuse of market power is defined as "*conduct that may be reasonably foreseen as likely to materially undermine the fair, efficient and openly competitive operation of the market.*"

Overall, it is my impression that prior to MSA's consultation in 2010 surrounding the OBEGs, the existing legislation did not provide a clear picture as to whether the exercise of unilateral market power was considered to be offside of the existing legislation. My interpretation is that a blatant or systematic pattern of economic withholding might well have been labelled as an 'abuse of market power'. The OBEGs clarified to market participants that this was not to be the case going forward.

In terms of timing, the MSA released the finalized OBEGs in January of 2011, having posted a similar draft to its website in November 2010. However, the stakeholder consultation used to formulate these final guidelines was quite extended beginning in February 2010. In terms of the guidance surrounding unilateral market power, the MSA made it clear in these consultations that it did not view economic withholding as anticompetitive market conduct (see "Market Participant Offer Behaviour: Illustrative Examples", September 2010 for example).

> 'The MSA has made it clear that a strategy aimed at raising the Pool price through economic withholding or lowering it by offering below cost, is not, by itself, going to be challenged. Further, the MSA has stated that it will monitor behaviour of this kind but only begin to be concerned if there is evidence that the market participant undertook additional actions to prevent or impede competitive response, what is referred to as abusing market power.'

6.4.2 The OBEGs: Econometric Analysis

To illustrate how the market power measures can be used to analyze the impact of market events on generator offer behaviour, the thesis utilizes the econometric approach outlined in section 6.3, using the Adjusted RSI measure and with the same independent variables being used to account for marginal cost changes. To analyze how the offer behaviour of Alberta's larger generators may have changed in response to the OBEGs requires specifying when this event took effect. For the econometric results presented below I assume that the event took place when the draft OBEGs document was published to the MSA's website on November 26th 2010. Therefore, from November 26th 2010 until the end of the sample period is assumed to be post-OBEGs and prior to this is pre-OBEGs. By splitting the sample period in two, the data can be pooled into two separate periods and the econometrics estimates for each can be obtained.

The econometrics analysis also allows for the Wald test to be used to decipher whether the market power coefficients in the post-OBEGs are statistically different from those observed in the pre-OBEGs era. The results of this test are reported in the right-hand column of Table 18. The Wald test follows the F-distribution and illustrates whether the null hypothesis, that the market power coefficients were unchanged, can be rejected. A larger value of the resulting F-statistic, and the associated lower probability value, implies a greater degree of certainty that the market power coefficient changed. As shown by the results presented in Table 18, the econometric estimates show that almost all of the assets saw a distinct change in their offer behaviour in response to market power as a result of the OBEGs. The only exception to this is ATCO's Joffre asset, which has a probability of 0.12 and is subsequently rejected at the 5% or 10% significance level. For all other assets analyzed the probability is 0 to 4 decimal places implying a strong degree of certainty that the offer behaviour of the asset altered from the pre to

the post-OBEGs era. In summary, the econometric analysis illustrates that generator offer behaviour changed significantly as a result of the MSA's OBEGs.

Table 19: Econometric Results pre and post OBEGs for various units

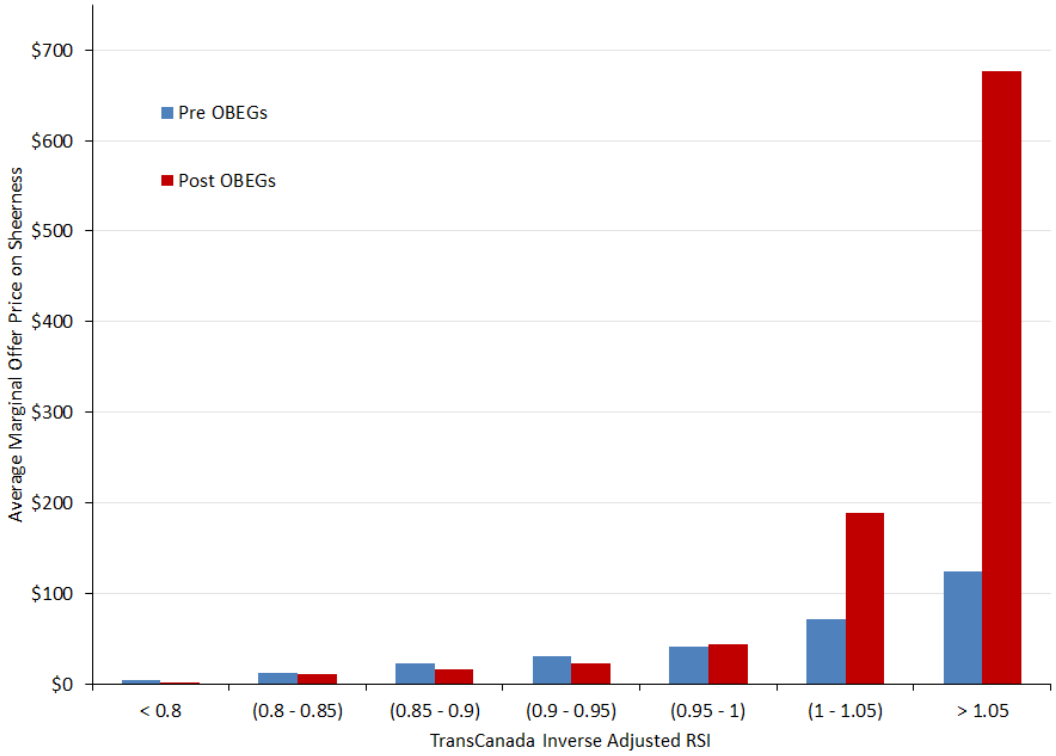
Generation Asset	Fuel	Offer Control (Secondary)	Coefficient Pre OBEGS (95% Confidence Intervals)	Coefficient Post OBEGs (95% Confidence Intervals)	Estimated Change	Wald F-Test
Sheerness	Coal	TransCanada	$20 ($18 - $23)	$96 ($86 - $106)	$76	213 0.0000
Sundance B	Coal	TransCanada (TransAlta)	$6.80 ($6.07 - $7.48)	$53 ($46 - $61)	$46	146 0.0000
Keephills	Coal	ENMAX (TransAlta)	-$0.10 (-$0.20 - $0.01)	$2 ($1 - $3)	$2.1	17.61 0.0000
Battle River	Coal	ENMAX (ATCO)	$2.43 ($2.19 - $2.67)	$8.87 ($7.92 - $9.82)	$6.4	165 0.0000
Crossfield	Gas	ENMAX	$77 ($62 - $98)	$28 ($19 - $38)	-$49	29 0.0000
Calpine	Gas	ENMAX	$39 ($31 - $47)	$14 ($11 - $16)	-$25	32 0.0000
Gensee 3	Coal	TransAlta (50%) Capital Power (50%)	$0.69 ($0.32 - $1.06)	$28 ($23 - $33)	$27	100 0.0000
Poplar Creek	Gas (Cogen.)	TransAlta	$7.3 ($5 - $10)	$26 ($20 - $31)	$18	34 0.0000
Joffre	Gas (Cogen.)	ATCO	$34 ($28 - $40)	$41 ($35 - $47)	$7	2.37 0.1239
Sundance C	Coal	Capital Power (TransAlta)	$3.49 ($2.73 - $4.25)	$24 ($19 - $29)	$21	60.64 0.0000

The results in Table 19 show that for a large number of assets, the impact of the OBEGs was to increase the estimated market power coefficient. This is intuitive because, for the most part, generating companies will be selling into the energy market and will tend to profit from higher prices. Since the MSA's OBEGs clarified that unilateral exercises of market power were not offside, one would expect to see suppliers increase their use of offer strategies at higher levels of structural market power in order to increase market prices and raise profits.

The econometric results for Sheerness and Sundance B imply that the OBEGs increased the responsiveness of TransCanada to changes in the firm's ability to exercise market power. Prior to the OBEGs, TransCanada's marginal offer price on Sheerness would typically increase by $20 in response to a 0.1 increase in the firm's inverse Adjusted RSI measure. Since the draft OBEGs were published the estimated market power coefficient is $96, implying that the OBEGs and the associated consultation process had an important impact on TransCanada's offer behaviour.

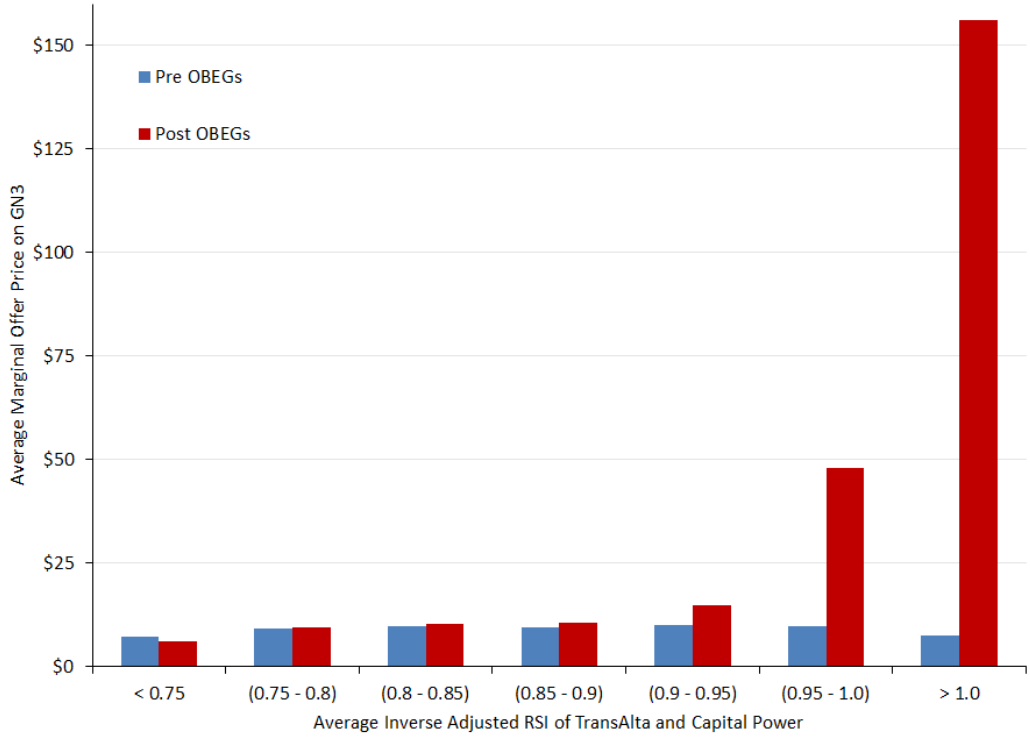
Figure 48 provides a quantitative illustration for how the marginal offer price on Sheerness varied at different levels of structural market power from pre to post-OBEGs. As shown, the offer behaviour on Sheerness changed notably at higher levels of structural market power. Prior to the OBEGs TransCanada's offer behaviour on Sheerness at higher levels of structural market power was relatively reserved. For example, in hours when TransCanada's adjusted RSI was greater than 1.05 (meaning the firm's priced generation was significantly pivotal) the average marginal offer price on Sheerness in the pre-OBEGs era was little over $100. In the post-OBEGs the same figure was close to $700. From this analysis it is apparent that the increase in the market power coefficient on Sheerness was the result of TransCanada being more aggressive in its attempts to increase price at higher levels of structural market power after the OBEGs.

Figure 48: The Average Marginal Offer Price on Sheerness at different levels of market power



As well as Sundance B and Sheerness, Table 19 also highlights a meaningful increase in the market power coefficient on Genesee 3, Sundance C and Poplar Creek. The change in offer behaviour on Genesee 3 is particularly striking because prior to the OBEGs the market power coefficient was barely significant from $0, implying that the unit was consistently offered at, or very close to, marginal cost throughout pre-OBEGs, and the structural market power of TransAlta and Capital Power was irrelevant in determining the generator's marginal offer price. In the period after the draft OBEGs, the average structural market power of TransAlta and Capital Power became significantly more apparent, with the coefficient estimated at $28. As shown by Figure 49 it is again clear that this increase is the result of the asset being offered at higher prices when the firms have the ability to increase market prices by doing so.

Figure 49: The Average Marginal Offer Price on Genesee #3 at different levels of market power



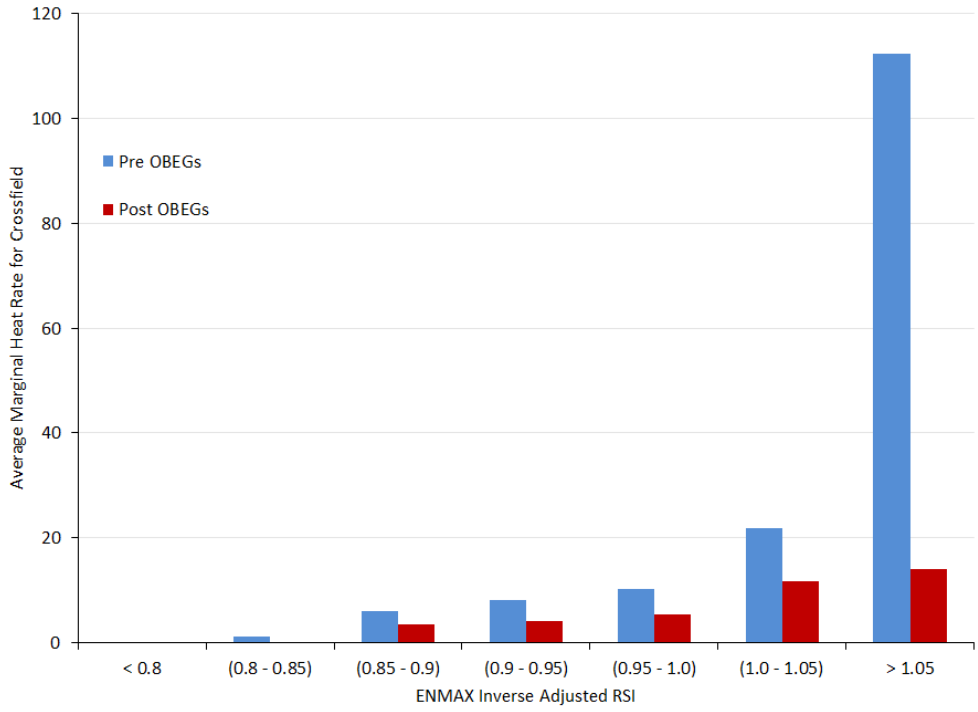
As with the econometric results detailed in section 6.3, the econometric results on ENMAX's units are again different to the econometric results on other assets. The market power coefficient on both of ENMAX's coal units increases marginally in the post-OBEGs although their resulting coefficients remain modest and are still well below the estimates on other thermal units.

It is also interesting to see that that ENMAX's gas units show a significant fall in their response to the firm's market power in the post-OBEGs period. A major difference between ENMAX and the other large participants in the Alberta market is the firm's fixed-price sales in the retail market. As a result of these sales, ENMAX's response to the OBEGs appears to have been trying to mediate the offer behaviour of other participants when structural market power estimates are high by running its gas units. The obvious explanation for this is that market demand is often peaking when structural market power estimates are notably high. During these

times, it may well be in ENMAX's best interest to keep market prices low, and reduce the costs of serving its retail obligations. This will definitely be the case if the prevailing market tightness is also driven by one of ENMAX's coal units being offline. As shown by Figure 50 the fall in the coefficients on ENMAX's gas units is indeed the result of changes in the firm's offer behaviour at higher levels structural market power.

A related explanation is that loads in the province may have responded to the OBEGs, and the resulting offer changes, by hedging their electricity consumption through long-term contracts with ENMAX's retail arm. Further fixed-price sales through it retail arm would increase the incentives ENMAX has to keep pool prices low when its ability to influence these prices is quite high.

Figure 50: The Average Marginal Offered Heat Rate on Crossfield at different levels of market power



To further confirm this intuition Table 20 below shows the estimated market power coefficients on Capital Power's Cloverbar gas units in three different segments of the sample period. Prior to July 2011 Capital Power was effectively a vertically integrated generator with a large amount of fixed-price sales through the EPCOR Regulated Retail Option ('RRO'). As with ENMAX, the initial response of Capital Power to the OBEGs caused a reduction in the estimated market power coefficient on Cloverbar, with the estimate falling from $44 to $16. However, the estimated coefficient subsequently increased significantly as these retail obligations were transferred from Capital Power to EPCOR. This result again highlights the importance of incentives in determining the extent to which generators respond to changes in their ability to influence market outcomes.

Table 20: The impact of the OBEGs and the EPCOR RRO on Cloverbar's offer behaviour

Generation Asset	Fuel	Offer Control	Coefficient pre OBEGs and pre RRO (95% CIs)	Coefficient post OBEGs but pre RRO (95% CIs)	Coefficient post OBEGs and post RRO (95% CIs)
Cloverbar	Gas	Capital Power	$44 ($34 – $54)	$16 ($13 – $19)	$122 ($105 – $140)

6.5 Broader Implications (a simple Counterfactual Analysis)

To discuss the broader implications of market power in the Alberta electricity market requires a discussion of its impact on the pool prices observed in the market. It is possible to make use of the regression results tabulated in the preceding sections in order to construct a 'counterfactual' market supply curve. This counterfactual supply curve could then be used to figure out what pool prices might have been in the absence of market power being exercised by some of the larger generators in the Alberta electricity market.

However, using the regression results discussed previously to analyze how offer behaviour may have affected market prices presented a number of issues, which may indicate the need for future refinements. Firstly, the market power measures used to obtain the regression results are focused on the ability of generators to influence prices in the Alberta market. None of the market power measures speak to profitability, or the incentives that the generators might have to increase prices through changing their offers.

As discussed in section 5.3 of the thesis, the profitability of exercising market power will depend upon the firm's exposure to the prevailing market price. Since the firm's exposure to pool prices will change as their financial trading positions alter, it should be expected that a firm's pricing response to changes in its ability to exercise market power will not be constant over time. Another important factor that can meaningfully influence the financial exposure of the larger generators in Alberta is the Availability Incentive Payments (AIPs) schedule within the Power Purchase Arrangements. Since the AIPs are based on 30-day rolling average pool prices, a firm's pool price exposure today will be affected by the availability of its PPA units over the next 30 days. As a consequence, the exposure of the larger firms in Alberta to the market pool prices is dynamic, and can be heavily influenced by expectations formed around PPA outages.[74]

The dynamic nature of a firm's overall pool price exposure means that firms will optimally vary how responsive their offer prices are to changing market fundamentals. In this way, it is useful to view the regression results reported above as an average of how responsive offer prices on

[74] This will be most notable in the event of a force majeure arbitration. PPA units that are offline for an extended period will likely be subject to a claim of force majeure by the owner. At this point, the pool price exposure of the owner may be 0 MW or -300 MW (this is just an example, the 'target availability will depend on the size of the unit) while the buyer's exposure may be 0 MW or +300 MW. Neither party will know for certain until an arbitration decision has been made, which can take upwards of 2 years.

particular units are to changes in a firm's ability to influence prices. Applying these average coefficients to specific time periods is problematic because in practice the coefficients may be quite variable. While it is possible to run the regressions for shorter time periods, this often leads to small sample issues. In summary, the market power measures must begin to account for changes to a firm's incentives in order to be useful for undertaking a counterfactual analysis.

Secondly, the regression results reported in the preceding sections use the marginal offer price as the dependent variable. The marginal offer price is defined as the highest priced block that is dispatched. This approach has been utilized by Wolak and McRae (2012) and Wolak (2013) to analyze how generators respond to their ability to exercise market power in New Zealand and in Alberta. This approach can be used to analyze how firms respond to market power changes because a unit's marginal offer price should remain constant in the absence of cost, production level or operational changes. However, while changes in the marginal offer price may be indicative of how offer prices on units are altered in accordance with changing market fundamentals, they may not be representative of how the entire offer curve may have been changed.[75] Clearly, to determine the impact of a firm's offer behaviour on market prices requires considering how the entire distribution of offers is altered. In this respect, the regression analysis could potentially be improved by using a measure of how much the offers are marked-up, although this too raises issues such as clarifying a baseline offer price.

As a result of these issues, the prudency of using the regression results to construct an hourly counterfactual supply curve is clearly questionable. That said, some of the overriding

[75] For example, if a firm responds to an ability to exercise market power by offering half of its capacity at $25 (marginal costs) and the other half at $999.99, its marginal offer price will likely remain at $25, thus indicating no change in offer behaviour.

econometric results can be used to discuss and analyze the implications of market power in the Alberta market. As shown in section 6.3.4, the offer prices on the coal plants at Sheerness and Sundance B are quite responsive to changes in the ability of TransCanada to exercise market power. In addition, the market power results reported earlier highlight that in some periods TransCanada's ability to exercise market power is high. Therefore, it is reasonable to assume that changing the offer prices on these units will have a material impact on the observed market prices in some hours. In total, the four units have around 800 MW of dispatchable capacity that can be offered into the market at a price.[76]

The regression results for Sheerness and Sundance B also implied that the offer prices on these units are rarely changed when TransCanada's Adjusted RSI index is below 0.95. Therefore, we can make use of the marginal offer prices observed on Sheerness and Sundance B in these hours to inform how TransCanada would offer these units in the absence of having market power. This in turn allows us to construct a counterfactual supply curve, and analyze how much of an impact the observed offer prices on Sheerness and Sundance B had on the resulting market prices.

In hours when TransCanada's Adjusted RSI was below 0.95 the median marginal offer price for Sheerness was $23.35 (this figure excludes hours when the marginal offer price is $0 because these observations will mainly be driven by operational issues). The same figure for Sundance B units is $23.24. However, it is not particularly abnormal to see these units dispatched at slightly higher prices, and the 90th percentile of the marginal offer price on Sheerness in these hours is $37, while the same figure for Sundance B is $33. Using these figures we can estimate a simple

[76] The two units at Sheerness units each have a capacity of 390 MW and a minimum stable generation of 135 MW, leaving 510 MW of dispatchable capacity that is typically available. Doing the same calculation for the two Sundance B units yields around 260 MW of dispatchable capacity (assumes an MSG of 250 MW for each unit).

counterfactual supply function and begin to discuss the broader implications of market power. In particular, for each hour in 2011 the observed supply function is altered by taking any offer blocks on Sheerness that are priced above $37 and pricing them at $23.35. The same is also done for Sundance B; any offers above $33 are reduced down to $23.24. The resulting counterfactual supply curve can then be used calculated a counterfactual System Marginal Price (SMP) for each observed SMP. This is done by assuming that the demand observed[77] for each SMP remains constant. The counterfactual SMP is then set by the highest priced block in the counterfactual supply curve that is required to meet this demand. For each hour in 2011, the counterfactual SMPs are used to calculate a counterfactual pool price by taking the time-weighted average.

It is worth highlighting that this simple counterfactual analysis is subject to many of the same criticisms outlined in section 4.8 of the literature review. In particular, the dynamic nature of the Alberta electricity market means that changing the offer prices on Sheerness and Sundance B, whilst holding all else constant, is unrealistic. In reality, the behaviour of other market participants would not have been the same had Sheerness and Sundance B been offered differently. For instance it is likely that lower offers on Sheerness and Sundance would have caused less supply, through imports and gas-fired capacity, and potentially higher market demand than was observed. These dynamics would imply that the counterfactual prices calculated would be too low. On the other hand, other larger generating companies may have responded to the high pricing on Sheerness and Sundance B by pricing-up their own units, and had Sheerness and Sundance B been priced lower, and the market more competitive, their units

[77] The number of megawatts dispatched in the Energy Market.

would have been offered at lower prices. This dynamic would imply that the counterfactual prices calculated are too high.

In any case, the broader conclusions stemming from the counterfactual analysis remain unchanged. Figures 51 and 52 illustrate the effect of lowering the offers on Sheerness and Sundance B on the price duration curve for 2011. In 2011 the average hourly pool price observed was $76. The counterfactual average pool price calculated was $24 less than this, coming in at $52. Therefore, it is clear that the offer prices observed on Sheerness and Sundance B were a significant factor in determining average pool prices in 2011.

However, as shown by the duration curves below, the pool prices observed in many hours of the year remained largely unaffected. For instance, the 80th percentile of the observed prices is only $6 higher than the 80th percentile of the counterfactual prices calculated. At the 90th percentile, however, the difference between the two is $70, and by the 95th percentile the difference is $304. It is also worth noting that at the highest percentiles, the observed and counterfactual prices converge once again. The intuition here is that some of the highest priced hours are the result of scarcity, and in these hours market prices would be close to the market price cap of $1,000 whether market power is being exercised or not.

Figure 51: Realized and Counterfactual Price Distribution Curves

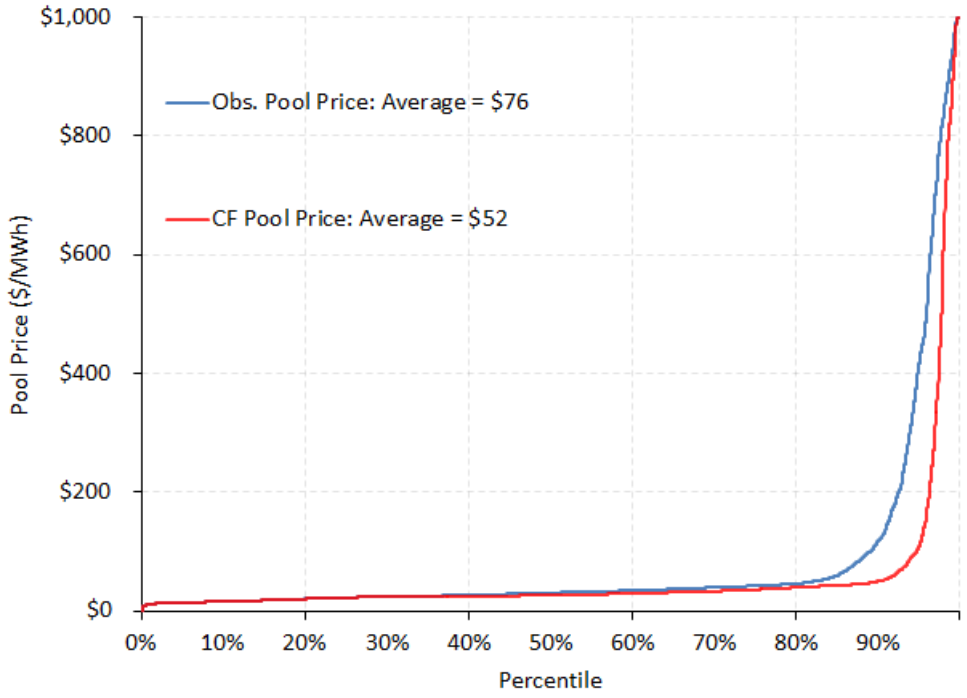
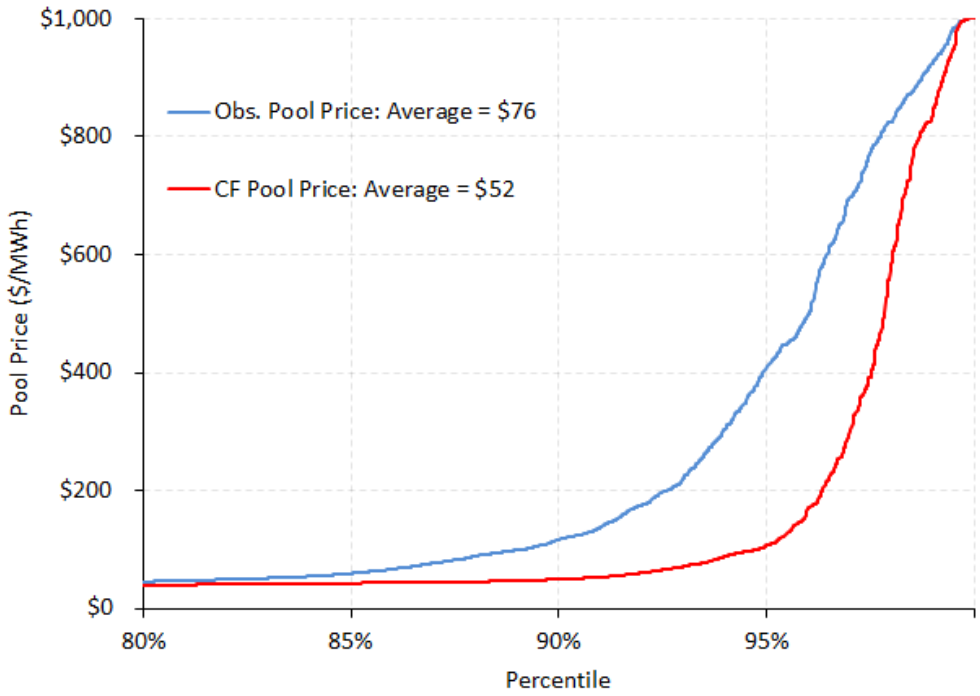


Figure 52: The Realized and Counterfactual Price Distribution Curves (80th percentile and up)



These insights are consistent with the preceding analysis and characterization of market power in Alberta's electricity market. In the majority of hours the market power of the larger generating firms is limited, and in these hours observed offer prices tend to be competitive, and pool prices tend to be low. In the remaining hours, the larger firms do have the ability to influences prices, and sometimes quite substantially. Therefore, in these hours, the pricing decisions that are made by the larger firms can be an important influence on the settled prices. This relationship is shown by Figure 53.

Figure 53: The Contribution of Adjusted RSI groups to the Average Observed and Counterfactual Prices

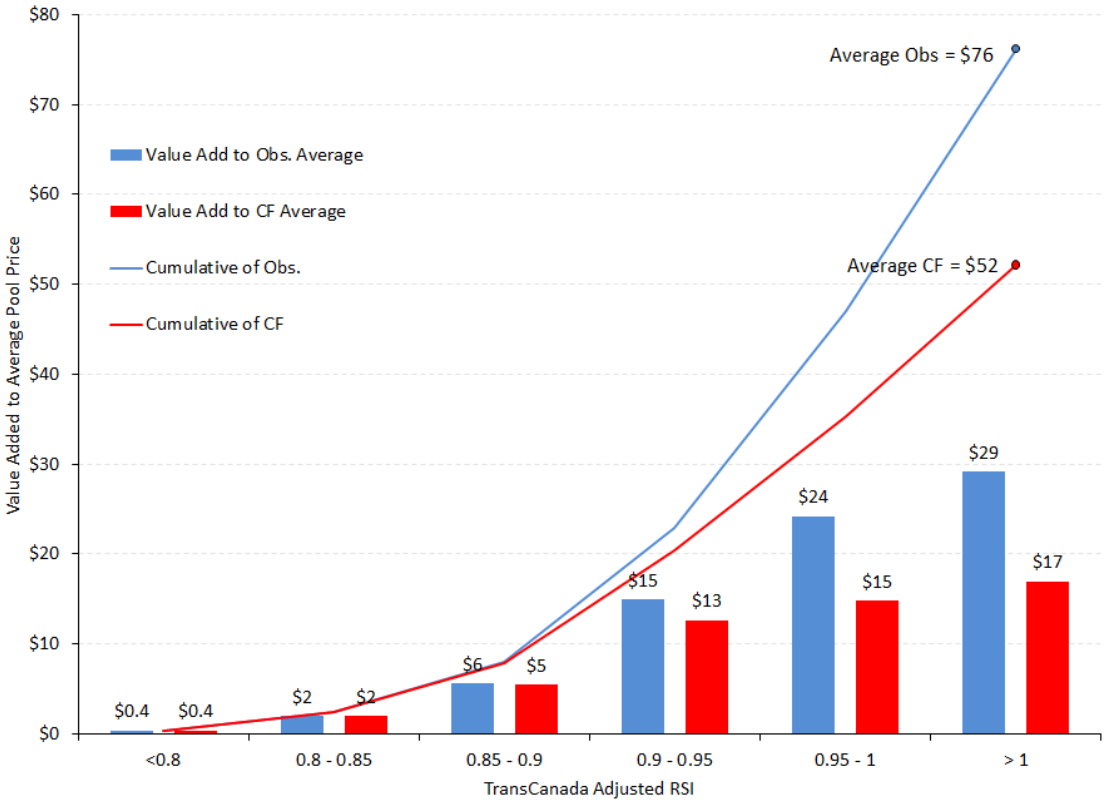


Figure 53 illustrates the value-added to the observed and counterfactual averages at different levels of TransCanada's adjusted RSI. For instance, all the hours in 2011 in which TransCanada's Adjusted RSI was between 0.85 and 0.9 accounted for $15 of the observed

average annual price. In the counterfactual calculations, these same hours show a similar level of contribution to the average, at $13, thus indicating a small difference between the observed and counterfactual prices in these hours, and at this level of market power. At higher levels of structural market power the difference between the observed and counterfactual prices is more notable. The hours in which TransCanada's adjusted RSI is above 0.95 account for 90% of the $24 difference in average prices. The difference in contribution is most notable for the hours in which TransCanada's adjusted RSI is greater than 1.0 because these hours account for 51% of the average price difference but represent only 9% of the hours in 2011 (see Table 21).

Table 21: The Contribution of Adjusted RSI groups to the Average Prices in 2011

Adj. RSI Group	Value Add to Obs. Average [A]	Value Add to CF Average [B]	Difference in Value Add [A] - [B]	Percentage of Difference	Percentage of Hours
<0.8	$0.4	$0.4	$0.0	0%	3%
0.8 - 0.85	$2.0	$2.0	$0.0	0%	12%
0.85 - 0.9	$5.6	$5.4	$0.1	1%	23%
0.9 - 0.95	$15.0	$12.6	$2.3	10%	30%
0.95 - 1	$24.2	$14.8	$9.4	39%	24%
> 1	$29.1	$17.0	$12.2	51%	9%
Totals	***$76.2***	***$52.2***	***$24.0***		

These observations are important because they highlight that the successful exercise of market power requires some level of market tightness (i.e. a shortage of competing supply relative to market demand). In this way, the exercise of market power by the larger generators serves to flatten out the distribution of prices at the higher end of the distribution curve. In the absence of market power, the 85^{th} – 99^{th} price percentiles would undoubtedly be much lower. Under this kind of price distribution new investment in Alberta's energy-only would be heavily reliant on a few hours in which the market is genuinely scarce of capacity in order to cover the fixed and

sunk costs. At present, these scarcity rents are limited by the $1,000 price cap and by the fact that genuine scarcity events are few and far between.

The exercise of supplier market power will increase the profitability of generation capacity developed in Alberta so in the long-run it should serve to incentivise new investment. In particular, by increasing the higher end of the pool price distribution, the exercise of market power would seem to favour the development of peaking capacity that is designed to run in the top 15-20% of the hours. As noted by the Brattle Report (2012), this dynamic inherently means that new entrants are reliant upon the continued exercise of market power by the incumbent generators. However, this is a fine balance because the entry of new firms will naturally serve to lower the market power held by the incumbent firms, thereby lowering prices. Because of this dynamic, the economic model of Cournot predicts that new entry will only occur if the new entrant reckons that post-entry prices will be sufficient to cover the average costs of operating. In other words, new entry into the market should occur up until the point at which market power becomes insufficient to warrant further entry.

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