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An Economic Analysis of Regulating Reserves Market in Alberta

by

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled "An Economic Analysis of the Regulating Reserves Market in Alberta" submitted by Margaret Tepczynska in partial fulfillment of the requirements for the degree of Master of Arts.

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Abstract

Ancillary services are an integral part of the electricity industry. They sustain the security of the entire electric system and ensure that the lights stay on. This thesis evaluates the efficiency of the Alberta ancillary services markets, in particular the market for regulating reserves over the period January 1, 2002 to September 30, 2002. Excess profits were calculated in order to determine the level of competitiveness of the regulating reserves market. If the regulating reserves market is operating efficiently then there should not exist any excess profits in the market. I find that over the nine month period the excess profits averaged $28,271.12 per contracted volumes in the on peak period. I further calculated the expected profits including the actual capacity fee and the break-even fee. In the on peak periods, firms participating in the regulating reserves market earn on average 42 % more than what they would if the capacity fee was set to equate

$\pi_{regulating} = \pi_{energy}$.

The excess profits in the off peak period averaged $7,274.817 per contracted volumes. Under the current pricing scheme, in the off peak times, firms earn 65% more than they would if break even fee was implemented.

Acknowledgements

I would like to thank my supervisor, Dr. Aidan Hollis for his invaluable guidance and expertise as my thesis progressed.

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Dedication

In the memory of my loving grandmother

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Introduction

A number of jurisdictions around the world are currently undertaking initiatives to deregulate the electricity industry. These initiatives attempt to replace the heavy hand of regulation with the light hand of market mechanisms. It is believed that in the long-run, restructuring will allow the electricity industry to generate benefits that are associated with a competitive market – lower electricity rates, efficiency in production and in allocation of electricity supply. In the short-run, however, the transition towards a deregulated electricity industry is proving to be a bumpy journey.

The government of Alberta initiated the deregulation of electricity industry in the early 1990s with the first wholesale electricity market, beginning operations on January 1, 1996. Due to extreme market concentration, market power was identified as a problem that needed to be addressed before a competitive generation market could truly develop. The solution was a virtual divestiture of assets via twelve Power Purchase Arrangements auctioned in 2000[1]. Within the PPA contractual framework, it was decided that to ensure a competitive market, no one firm could hold more than twenty percent of the total generation rights. Under such rules, it was hoped that no supplier would be large enough to increase the market price by withholding or overpricing some of its energy product. The PPA also increased the number of market participants and dissipated the market concentration. Thus, it was expected that the Alberta *energy* market, with free entry and exit, many market participants and a regulatory body actively overseeing the behaviour of the generators, would work quite competitively.

[1] 1 For furhter discussion of Power Purchase Arrangements, see Bacalso, M.N.(2000)

What is not clear is whether the market for ancillary services, sometimes known as system support services, would be able to achieve a comparable level of competitiveness. This thesis makes a preliminary assessment of the Alberta ancillary services market's competitiveness.

Power systems experience frequent disturbances such as short circuits or loss of generators or transmission lines. When this occurs, frequency and voltage immediately begin to drop. If the drop is prolonged, load must be shed in order to rebalance demand and supply. Ancillary services allow the system operator to keep the system in balance, to maintain voltage at the right level and to restart the system when it suffers a complete collapse. Thus, ancillary services sustain the security of the entire system and ensure that the lights stay on (Stoft, 2002, 235).

Since the maximum amount of output a generator can provide is fixed at the capacity of a unit, this capacity can be allocated between energy and ancillary services, rendering the two products substitutable. Thus, the decision to operate a unit of ancillary services cannot be isolated from the decision to not operate the unit to produce energy. A generator selling ancillary services must forgo profits in the energy market. Hence, the cost of supplying ancillary services is the opportunity cost of not providing energy (Brien, 1999, 4).

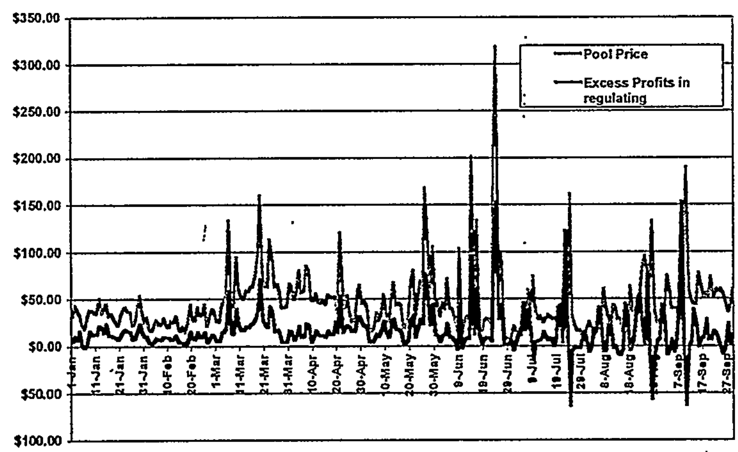
When creating markets for ancillary services, it is essential to understand the relationship between generating electricity and providing ancillary services and the options the plant owner faces when selling into the two markets. The manner in which ancillary services are purchased, because of the substitutability in supply between the two markets, affects not only prices for ancillary services but also the prices in the energy markets.

The objective of this thesis is to evaluate the efficiency of the system support services market, in particular the market for regulating reserves. If the regulating reserves market is perceived to be competitive then there should not exist any excess profits in that market, where excess profits are defined as the difference between what a single megawatt-hour would earn in the regulating reserves market less what it would earn in the energy market. Figures 1 and 2 show excess profits in regulating reserves over the first three quarters of 2002. One obvious inference from the figure is that higher prices in the energy market led to even higher prices in the regulating reserves market. An argument for market power in the regulating reserves market is that of limited entry and exit. Due to technical requirements not all of the generators participating in the energy market can bid their capacity into the regulating reserves market. The opportunity to exercise market power appears to be more severe the higher the Power Pool prices. This finding suggest that over the nine month period, the two markets did not fully converge in terms of profit opportunities, and markets were not operating efficiently over that time. Expected profits in the energy market averaged \$38.74 per MW hour in the on peak period and \$10.40 in the off peak period. Expected profits in the regulating reserves market were calculated as \$53.47 for the on peak condition and \$18.74 for the off peak. Furthermore, excess profits in the regulating reserves market averaged \$14.73 for the on peak (\$29.48 more than in the energy market) and \$8.34 for the off peak (excess profits in the energy market for the same period averaged −\$8.34). Therefore, firms that are eligible to participate in the energy market and the regulating reserves market are more likely to choose the latter.

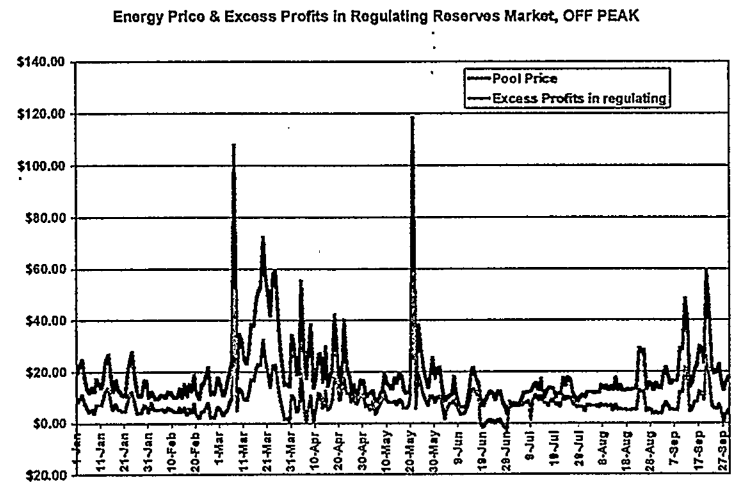
since they can earn greater profits.

Over the nine month period excess profits in the regulating reserves market averaged \$28,271.12 per contracted MWs[2] in the on-peak period with the highest earning of \$50,047.68 recorded in March 2002. In the off-peak periods the excess profits were considerably lower averaging \$7274.82 with the highest levels of \$8,377.61 earned in September. The total average profits for the on-peak period from January 1, 2002 to September 30, 2002 were equal to \$254,440 while generators in the off-peak series earned in total \$66,576.19.

Energy Price & Excess Profits in Regulating Reserves Market, ON PEAK



[2] formula used to calculate the average excess profits is as following: average of (monthly price differential * monthly contracted volumes * the numbers of hours in use)



The structure of the thesis is as follows. Section II reviews the structure of the electricity industry. Section III discusses the notion of capacity requirements and the investment problems encountered by the power markets. Section IV describes the properties of the Alberta electricity industry: the energy market and the ancillary services markets. Section V describes the data. Section VI reports the findings of the market power in the regulating reserves market. Section VII concludes.

2 The Electricity Industry

Changes in both the regulatory setting and the ownership structure are being currently undertaken by many industries around the world. The last of the network industries to continue on the route towards the market-based environment is the electric power. The following subsections provide an insight into the transition of the electric industry from a natural monopoly to a more competitive market structure as well as explain the role that regulation has played in governing the provision of electricity.

2.1 Electricity Markets as A Network Industry

It was formerly believed that the electricity industry possessed characteristics of both the normative and positive natural monopoly. A normative natural monopoly is a structure for which the costs are minimized if there is a sole supplier. A positive natural monopoly means that barriers to entry are sufficiently high that there can only be a single supplier[3]. Hence, the electricity sector has been viewed as a natural monopoly in generation, transmission and distribution. Typically, a geographic region was served by a vertically integrated utility that would supply a bundled product to end consumers.

Transmission is the essential component of the electricity sector; it coordinates the efficient supply of electricity and in the era of deregulation has become a critical link that provides benefits of competition to both producers and consumers. Transmission sector was and still is thought of as a natural monopoly. The reasons for

[3] For further discussion of positive and normative natural monopoly, see Church and Ware (2000)

the transmission segment being a natural monopoly have changed over time. In the past, it was verified that if wires owned by different companies were allowed to interconnect to form a single network, the laws of physics demonstrated that there would be significant externalities: the flow on one line affects the capacity of other lines in the system to carry power. Although current transmission systems can be interconnected without jeopardizing the reliability of the system, (i.e. nowadays, connecting dispersed generating facilities allows for the substitution of production from high marginal cost units to low marginal cost generators while still meeting the total demand for electricity) transmission has retained its monopoly status since enormous costs would have to be incurred in order to duplicate the existing network.

Generation was argued to be a natural monopoly due to the large scale of efficient generation plants and the losses that occurred with the long distance transmission, which made it more efficient to have local areas served by one or a small number of generating plants. Over time, the optimal scale of generating facilities has declined, exhausted at a unit size of about 500 MW. Some studies have argued that at present, generation exhibits constant returns to scale and it is said that this sector of electricity market is subject to efficient competition (Borenstein et al., 2000, 5).

Restructuring initiatives have varied greatly across countries, implementing various combinations of privatization, liberalization and deregulation. However, although deregulation is becoming more sophisticated as jurisdictions enter the last stages of the process, few jurisdictions have addressed the question of how to properly unbundle and price ancillary services (which comprise both generation and transmission functions). Ancillary services allow the system operator to keep the system in balance, to maintain voltage at the right level and to restart the system when it suffers a complete collapse.

Traditionally, vertically integrated utilities provided ancillary services as a part of the bundled electricity product and consumers paid for them through cost-based electricity rates. Today, there are two approaches to the supply of ancillary services. The system operator can procure the necessary services in a market or it can assign each supplier a fraction of a physical requirement (so called self-provision).

Power systems experience frequent disturbances such as short circuits or loss of generators or transmission lines. When this occurs, frequency and voltage immediately begin to drop. If the drop is prolonged, load must be shed in order to rebalance demand and supply. Immediately after a forced outage all remaining generators increase their outputs with the extra power coming from the kinetic energy of their rotation, not from their fuel sources. As this energy is being depleted, the generators slow down and both the system frequency and voltage start to decline once more. In order to restore system frequency, the generators with excess capacity start to ramp up. If there are not enough of the ancillary services available in the required 5 to 10 minutes, the system operator has to shed load. Thus, ancillary services are the key elements ensuring that the system is capable of withstanding sudden disturbances, yet they play a significant role in raising prices and stimulating investment, thus contributing to adequacy (Stoft, 2002, 307).

2.2 Regulation of Natural Monopoly

Interaction of demand and the extent of the economies of scale determine whether a given industry is a natural monopoly. When the industry is thought to be a natural monopoly, there exists some justification for price and entry regulation. If the industry is a natural monopoly, entry by more than one firm is inefficient. Thus, the imposition of entry controls must be complemented with price regulation to prevent the allocative inefficiency associated with monopoly pricing. In the absence of regulation, the monopolist would be able to profitably set price above the marginal cost, thus reducing the surplus associated with the provision of electricity as well as infringing on the consumer surplus.

Thus, if leaving markets unregulated creates a potential for market power and cost inefficiencies, the regulated outcomes should be able to create a potential Pareto improvement. However only if the regulator has perfect information and the regulatory mechanism is capable of perfectly aligning the objectives of the firm and society will the regulated outcome be rendered superior.

In Canada and the United States, the cost-of-service (COS) regulation was thought to be the "second-best" pricing rule for a single firm. However, this method of regulating monopoly utilities gave limited incentives for efficient operations. Under the COS, the price that the regulator allowed the utility to charge its consumers was equal to the amount that the utility must be able to earn in order to generate a fair rate of return divided by the estimate of demand. Therefore, if costs increase so do prices and if the opposite happens then consumers benefit from lower prices but the firm's profit doesn't change. In addition, the regulated utility and regulatory body joint decision making process have had difficulty making economically efficient new generation capacity investment decisions both in terms of the size and fuel type of the generating facility[4].

2.3 Policy Prescription for Restructuring Electricity

The reform of electricity industries has typically followed the standard model applied to other network industries that have been deregulated in the last 20 years. The basic method of introducing competitive forces into those industries comprises three stages. First, there is unbundling: services provided by the natural monopoly segments are unbundled from the competitive services and non-discriminatory access to the essential monopoly facilities is mandated. Second, liberalization involves elimination of regulated entry barriers into potentially competitive segments. Opening access to competitors requires access regulation – when the supplier of the essential facilities also competes with the new entrants in the competitive segments, it may have incentives to discriminate against its competitors in the provision of access to its essential facilities.

The third step involves interconnection, where transmission and generation comprise an integrated system. Historically, transmission and generation were planned on an integrated basis by a vertically integrated utility under regulatory oversight. The traditional monopoly was able to have sufficient transmission to economically supply its load. Power system planners forecasted load patterns and generation availability and were able to create detailed models of the electric systems for peak and off-peak conditions. However, as the electricity industry moves towards a competitive mar-

[4]For further discussion of regulation in practice, see Church and Ware (2000)

ket structure, transmission adequacy becomes a critical – and not easily optimized – factor in the proper operations of the market. New investment in generation must coincide with transmission expansion so that there are no constraints on generation markets. The fact that the time to construct many generating units is now shorter than the time to build a new transmission line further complicates the transmission planning process.

2.4 Re-regulation and Internalizing Network Externalities

Under the old market design there was no explicit spot trading – a monopoly system controller simply gave directives to the generation units, they responded and all operating costs were pooled within the monopoly and were later recovered through tariffs charged to the consumers via the distribution companies. However, implicitly an economic dispatch process that determined real-time operations and minimized cost of meeting demand given real-time system conditions and security constraints must have been adopted if those monopolies were able to maintain reliability of the system and kept the lights on.

As a number of jurisdictions around the world refashion their electricity markets, they seem to be incorporating a model of spot market/economic dispatch as the best way to create effective and efficient competition in electricity. The lack of economic storability as well as the existence of price-irresponsive demand calls for some non-market process that must close the gap between the market and physical reality. Although a central regulatory process is indispensable in the electricity market, its role should be minimized in order to take advantages of the competitive forces and the inherent benefits they bring along. The only manner in which the system operator becomes a mechanic, tending the market-clearing machinery, is by relying on the spot prices that reflect physical reality (i.e. integrate real-time network externalities related to transmission congestion and peaking capability into trading). The concept that made real competition possible in electricity systems was the establishment of the Independent System Operator that manages a centralized spot market integrated with real-time operations and is open to competitive buyers. It is also responsible for all the network effects that must be dealt with if the system is to operate reliably (Ruff, 1999,6-14).

First-generation electricity markets have worked relatively well, considering that at the time they were established there was little theory on market-driven electricity systems. Although some mistakes have been made in the design of those systems, the trading and operating arrangements have in general been adequate enough to allow the state monopolies to be dismantled and in many cases privatized, resulting in some cases in improvements and increased efficiency. In England and Wales, competition has reduced costs and raised performance, but has put severe competitive pressure on the coal industry and made it hard for the middlemen and market makers to earn high transaction fees (Ruff, 1999,15-17).

A second generation of competitive market designs has attempted to create more refined market arrangements that better reflect reality. However, as electricity systems mature the trading arrangements are becoming even more sophisticated. Currently, system operators tend to impose fewer constraints on generating units so that the latter make more of their own operational decisions. On the other hand, system operators administer more sophisticated market mechanisms that are more closely integrated with real-time operations. Since real-time prices faced by the generators reflect actual real-time network effects, each market participant decides for itself how it wants to contract and operate in response to its own forecasts of real-time prices and its own constraints such as a unit commitment costs and ramping rates. The system operator clears the short-term spot market and manages events within each market period. The system operator also operates day-ahead and hour-ahead markets to help market participants predict and hedge against real-time prices.(Ruff,1999,5-10)

2.5 Contemporary Market Designs

Power markets can suffer a catastrophic instability that develops in less than a second and involves hundred of parties interacting with each other. The extent and speed of the required coordination calls for the market that is tightly controlled in real time. Some of the current market design controversies focus on the extent of the system operator's role, while others revolve around the day-ahead markets and their operations. All central day-ahead market run by system operators are organized as auctions. There exist four day-ahead markets and, although some trade energy and other sell transmission, they all use the same method for choosing which bids to accept and how to set prices (Stoft, 2002, 223-231).

A power exchange market does not use side payments, but employs one-part bids which consist of only supply or demand curve. The auction first finds the set of supply and demand bids which would maximize the total surplus to all market participants. Then the market price is determined at each location by the marginal surplus of additional supply. The system operator ignores the unit commitment problem.

A transmission-rights market requires a complex pre-market step for market participants: buyers and sellers must find each other and make provisional energy trades that are contingent on the outcome of the transmission market or must buy transmission on speculation. The auction finds the set of supply and demand that will maximize total surplus from the transmission sold in the auction subject to the transmission constraint. The price of transmission is set to the marginal surplus of increasing the transmission limit from X to Y, if the path in question is not constrained,then the price is zero.

A power pool is a centralized market that uses side payments to pay different prices to different suppliers at the same time and location. These payments are only made if an accepted supplier would lose money on its as-bid costs (energy cost, start-up costs and no-load costs) given the pool price. The auction maximizes the total surplus of the accepted bids subject to transmission constraints, and ramp-rate limits. Price is set equal to the marginal surplus at each location.

Setting the market price equal to the marginal surplus is justified since it gives the competitive price and induces efficient behaviour. It also clears the market, which means all accepted bids will comply with the settlement and all rejected bids will suffer no loss given the settlement price.[5]

The ability to rely on the competitive market forces to set the price of electricity has some desirable properties. First, it gives market participants proper signals for the timing and magnitude of new investment expenditures. In addition, because

[5] For further discussion of real time transactions and the day-ahead auctions see Stoft (2002)

firms have no influence over the market price, they have the maximum incentive to produce output at minimum cost and can rely only on higher profits by cost-reducing innovations not immediately imitated by competitors. However, the main benefit of competition comes from the demand side of the market rather than the supply side. The price spikes of the wholesale market will be passed onto customers and will cause at least the marginal consumers to curb their demand when price is highest and generation most costly. A price-responsive demand will result in less generation being built and hence will reduce the total cost of providing power. A competitive market will pass those savings on to consumers.

3 The Problem of Capacity Requirements

A move towards an increasingly competitive electricity market instills a profit motives in all of the market participants. Their decisions regarding investment in new generation are made based on the expected profitability of the projects rather than on the overall need for more generation in order to sustain the reliability of an electric system. This section discusses at length the ways firms determine the level of their investment, when faced with inelastic demand. This issue is particularly relevant to the question of how ancillary services market will be set up, since ancillary services may be called on to replace shortfalls in generation. Empirical evidence, supported by economic theory, suggest that under current market conditions, power markets are unable to determine an optimal level of investment. If a laissez-faire attitude was allowed, then markets would suffer extreme price spikes, so that some regulatory oversight is needed in order to provide appropriate investment signals. The following subsections attempt to identify the regulatory price setting mechanisms and describe how they work in practice.

3.1 Generation Adequacy

Historically, decisions on the amounts, locations, types and timing of investments in new generation have been made by vertically integrated utilities with the approval from the Alberta Energy Board. As the Alberta electricity industry is restructured, these decisions are being fragmented and dispersed among variety of entities.

As generation is deregulated and becomes increasingly competitive, decisions on whether build new generators and to retire, maintain or re-power existing units will be made by unregulated for-profit firms. These decisions are largely based on investor assessment of future profitability and only secondarily on regional reliability requirements. Thus, profit-maximizing firms will weigh costs and benefits of additional investment without any regard to socially desirable levels of new generation.

Empirical analysis of the U.S. electricity industry shows that for at least the past several years, generation adequacy has declined and this downward trend will continue for the next decade. Utilities are reluctant to build new generation because of the uncertainties relating to the cost recovery of such investments in new competitive markets. Loss of integration between generation and transmission planning as well as the unwillingness to reveal construction plans early enough also contribute to the aforementioned trend.

The key issue around generation adequacy is whether competitive generation markets for capacity and energy will be sufficient to maintain socially desirable levels of reliability – or will the regulators need to impose mandatory minimum reserve obligations to ensure that consumers do not have their electricity supply involuntarily interrupted. These two options generate different outcomes in terms of price volatility, generation portfolios and consumer load profiles.(Hirst et al.,1999, 4-11).

Market forces cannot approximate optimal investment. Due to the lack of demand responsiveness to price, the market learns nothing from high spot prices about the consumer preferences for reliability. Most consumers do not even consider the question of how valuable reliability is to them. Hence, the required information (i.e. price signals consumer willingness to pay for reliability) does not exist. Since the market cannot resolve the investment problem on its own (and might grossly under-invest in generation), engineers and regulators have stepped into the breach. They control investment by setting price caps (Pcap), operating reserve (OR) requirements, installed capacity (ICap) requirements and/or installed capacity penalties.

3.2 Fixed Cost Fallacy

Many believe that competitive markets will not allow generators to recover their fixed cost of investment. Loeher (1999) argues that "in the U.S., the actual load exceeds 90% of the peak load only $1 - 2\%$ of the time. In the past utilities had an obligation to serve all of the load all of the time, even the last 10%. This was part of the regulatory compact. Thus they planned, built and operated as much generation as was required by the peak load. But today there is a question as to whether, in an industry driven by competition and the marketplace, investors will be willing to commit financial resources to supply customer load which will be realized only a few hours a year." (Loeher, 1999, 3-6).

However, as will be proven below, short-run competitive prices induce the right level of investment and allow investors to earn a return in the absence of the price unresponsive demand. It is the demand side flaws that prevent power markets from correctly estimating the competitive prices, hence there are no correct price signals that would allow investors to properly determine the desirable and optimal generation capacity investment.

A common fallacy asserts that if a generator always prices output at marginal cost it will fail to recover fixed costs of investment.

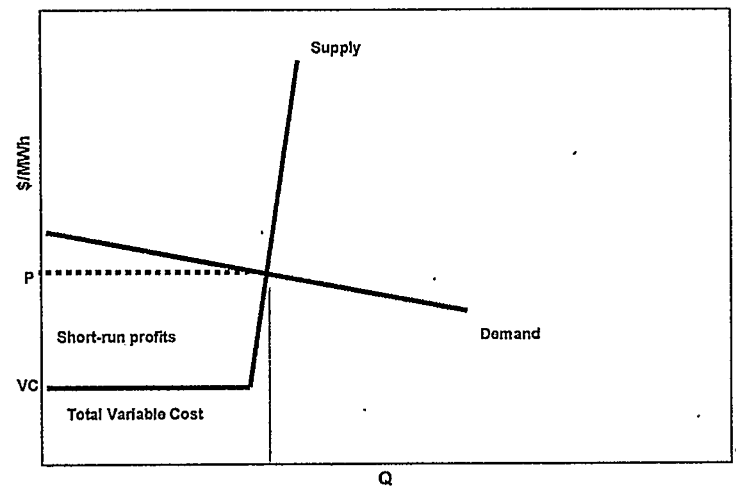
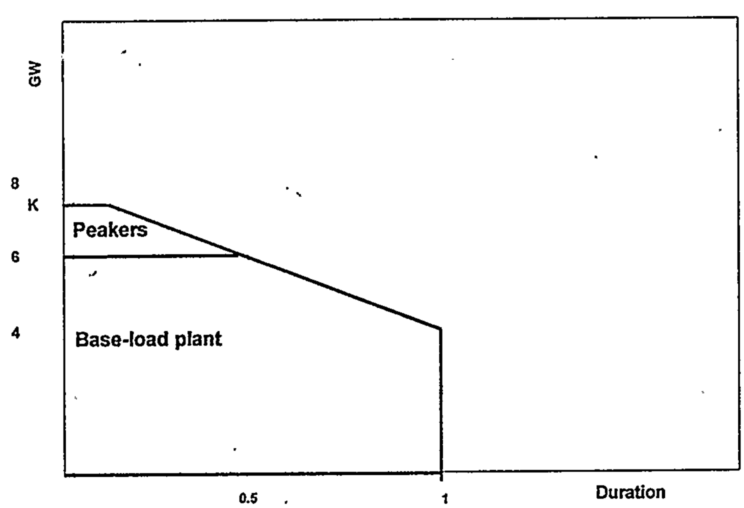


Figure 3 shows that revenue R (P times Q) is greater than total variable cost (TVC), thus the generator has money left over to cover its fixed costs (i.e. the generator is earning scarcity rents). If the market price is high enough, the generator will cover its fixed cost. If marginal cost prices did not cover fixed costs, investors would choose not to build new generation. However, as demand grew and generators wore out, the market would tighten causing prices to rise. On the other hand, if marginal cost prices more than cover fixed cost, more investment would flow into generation, supply would outstrip the demand and prices would fall. Consequently, price converges towards the point at which costs are exactly covered. Thus, in the long-run competitive equilibrium, generators recover their fixed costs even though price equals marginal cost at all times for all generators. The fixed cost recovery depends only on the ability of generators to enter and leave the markets as they see fit.

Although competitive prices will recover fixed costs, a weaker version of fixed cost fallacy claims that they will lead to a serious shortfall in generation capacity. Figure

4 confirms that in the presence of price spikes, the right amount will be invested in the peak and base-load generation. Short-run profits, and hence the ability of a peaker to cover its fixed cost depends on the price spike. The price spike determines the optimal investment in peak generation and indirectly sets the optimal amount of base load generation since peaker's fixed costs enter into the equation of a base-load generator. Thus, when the market experiences a price spike, the right level of peak capacity will be estimated which in turn will determine the amount of base load capacity needed to serve the power market. Figure 4 is used as a benchmark to establish how the competitive solution diverges from the optimal outcome, and further assesses that the competitive and optimal solutions yield exactly the same results and that inadequate investment in generation is caused not by inability to recover fixed costs but rather by price unresponsive demand. The flat spot at the top of the duration curve occurs if available capacity is less than $8GW$. Once generating capacity is exhausted, demand is limited by high prices.



The optimal solution accounts for the high cost of serving peak load, D_{Peaker} and the willingness to pay for this service. Under the optimal solution scenario, the system will spend some time with the load, L exactly equal to generation capacity, K. The duration of the flat load peak will be denoted by D_{PS} because at these times there is a price spike greater than the variable cost of a peaker, VC_{Peaker}. The average cost of energy, AC_E, including the fixed cost of capacity used to produce it is given by:

$$AC_E = \frac{FC_{Peaker}/cf + VC_{Peaker}}{MWh}$$

where cf stands for the capacity factor (percentage of utilization determined by the load's duration). Serving a load of duration D_{PS}, results in cf equal to D_{PS}.

$$AC_E = \frac{FC_{Peaker}/D_{PS} + VC_{Peaker}}{MWh}$$

Assume that the value of power to consumers is \$1000/MWh, FC_{Peaker} is \$6 and VC_{Peaker} is \$30, thus the condition for optimal peaker capacity is:

$$6/D_{PS} + 30 = 1000$$

$$D_{PS} = 0.62\% \text{ of the year } (\approx 54 \text{ hours per year})$$

Thus, if a peaker is needed less than 54 hours per year, it is not worth buying.

From Figure 4 we can infer that duration of 0.0062 corresponds to a load that is $25MW$ below the potential peak of $8000MW$. The flat peak is at $7975MW$, thus the total generating capacity should equal this peak load. Since the base-load capacity is determined to be optimal at $6000MW$ (determined by reading the screening curves to find that the trade-off point is at a duration of 0.5 and then reading the load duration curve to find that at this duration, load is $6000MW$), the optimal peaker capacity is $1975MW$. The competitive solution implies that in the long run, peakers and base-load plants must cover their fixed costs from short-run profits, thus

$$FC_{Peaker} = R_{Spike} \tag{1}$$

$$FC_{base} = FC_{Peaker} + (VC_{Peaker} - VC_{Base})xD^{*}_{Peaker} \tag{2}$$

Assume that $FC_{Peaker} = 6$, $VC_{Peaker} = 30$, $FC_{Base} = 12$, $VC_{Base} = 18$

(1) & (2) can be solved for the optimal durations and D^{*}_{Peaker}. Thus the $D_{PS} = 0.062\%$, $D_{Peaker} = 50\%$, base-load capacity $= 6GW$, and peaker capacity $= 1975MW$. Notice that these are exactly the values found for the optimal levels of capacity for both technologies. Consequently, competitive prices would cover fixed costs and induce the optimal mix of generation technologies. The deficiencies in current generation adequacy arise not from recovery of fixed costs but from the difficulty in achieving competitive prices in the face of the demand-side flaws.

3.3 A Simple Model of Reliability

An economic system is functioning efficiently when the price signals sent to consumers reflect the cost of serving them, when prices received by producers include the value of the goods and/or services being produced and the costs of production are being minimized. It is widely agreed that the competitive paradigm provides an appropriate model for the generation sector of the electricity industry. The big controversy is focused around the issues of choosing and pricing the capacity requirement. Many believe that traditional notions of capacity are artifacts of the regulated world and have no place in the efficient competitive electricity market. However, the proposition that the level of capacity should be determined solely by expectations of the spot prices for electricity is incorrect (Jaffe et al., 1998, 1-4).

Supply and demand constitute the core structure of every market; however, in the power market their interactions are very complex. Suppliers cannot store their output, so that the real-time production attributes are important and the demand-side flaws affects detrimentally the non-storability of the supply's output. Since power markets cannot operate on their own, they require a regulatory demand for a combination of the real-time energy, operating reserves and installed capacity. This demand is backed up by a regulatory pricing policy, also referred to as the reliability model. Price regulation is essential since it determines the height of a price spike (Stoft, 2002, 108-111).

In the following subsections I will go through two extensive models of reliability, VOLL pricing and Operating Reserves pricing, in order to show how different jurisdictions deal with the problem of investment adequacy.

Alberta uses the operating reserves pricing methodology in order to give generators proper investment incentives. It created the ancillary services market where participating generators can recover some of their fixed costs. The generators bid in their capacity reservation and those who get called on (i.e. are producing energy) earn energy profits. In the regulating reserves market generators are being called on with probability $t \approx 50\%$. Thus, the profits from being in the regulating reserves market depend on the energy price, the probability t of being used and the capacity fee. It is of great importance to note that the fee is positively correlated with the energy price. The following equations are formally derived in the Operating Reserves Pricing subsection and are used here only as an intuitive suggestion of market power in the Alberta regulating reserves market.

$$D_{PS}(K^E) = \frac{SR\pi(K)}{P_{cap}} \tag{a}$$

$$SR\pi = t * (PP - VC) + Fee \tag{b}$$

where D_{PS} is the duration of a price spike, $SR\pi(K)$ denotes the short-run profits in the regulating reserves market, P_{cap} is the price cap and PP is the energy price.

Equation (a) states that the duration of a price spike depends on the short-run profits and the price cap. We will treat P_{cap} as a constant. Equation (b) asserts that the short-run profits are determined by the fee and the price margin.

If the energy price (PP) is high, then $SR\pi$ in the regulating reserves market also goes up. Since the Fee is positively correlated with the PP, as PP increases so does Fee and $SR\pi$. Referring back to equation (a), an increase in $SR\pi$ results in a longer D_{PS}. This positive relationship between $SR\pi$ and D_{PS} allows generators to earn even higher profits over time.

The goal of the system operator is to induce the optimal level of investment K^E

$$K^E = L_{\max} + OR - \alpha\frac{SR\pi(K)}{Pcap} \tag{c}$$

where $L_{\max}$ is the maximum load, assumed constant, OR denotes operating reserves.

Thus when the $\frac{SR\pi(K)}{Pcap}$ increases, and $L_{\max}$ is constant, the system operator must procure more of the operating reserves (OR). Since there are only a few generators participating in the regulating reserves market, they can charge a higher fee for those additional reserves since the system operator needs those extra volumes to balance the electric system.

The operating reserves pricing model tells us that there is a potential for market power in the Alberta regulating-reserves market; we formally test whether this potential is realized in later chapters.

General Model Of Reliability:

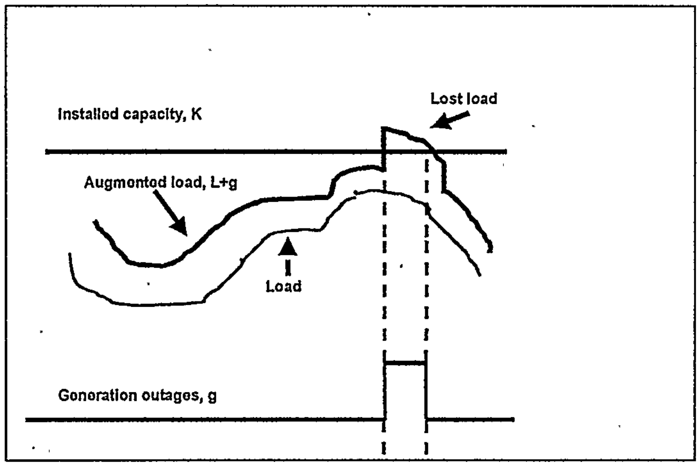
The general model of reliability states that as long as $D_{LS} < FC_{peak} < V_{LL}$, the regulatory pricing policy will induce the optimal level of investment. We explore this below.

Define operating reserves as $OR = K - g - L$, where K is a well-defined level of installed capacity, g represents generation outages and L is defined as the economic demand for power which would be consumed if the system were operating normally. L consists of served load and the lost load LL, which is measured by the extent to which OR is negative and is equal to zero whenever OR is positive:

$$LL = \max(-OR, 0)$$

Define Augmented Load as $L_g = L + g$, thus $OR = K - L_g$.

From the above equations we can infer that LL equals the amount by which L_g exceeds the installed capacity, K.



As Figure 5 suggests, given well-functioning security procedures, generation adequacy is the fundamental determinant of reliability. The greater is K, the smaller the area of lost load. Although increases in K reduce the cost of lost load they increase the cost of serving load. Thus, the optimal value of K is determined by the above cost trade-off.

Increasing K by $1MW$ would reduce the area of lost load by $\$(V_{LL} \times D_{LS})/h$, where D_{LS} is the duration for which L_g is more than K. As K increases D_{PS} (duration of a price spike) declines. For low values of K, $V_{LL} \times D_{LS}$ will be greater than FC_{Peak} and it will cost less to increase K than will be saved by the reduction in lost load. For high values of K the opposite is true. At the optimal K the cost saved equals the cost of installing another megawatt of peak capacity. The condition for optimal K is

$$V_{LL} \times D_{LS} = FC_{Peak}$$

or

$$D^*_{LS} = \frac{FC_{Peak}}{V_{LL}}$$

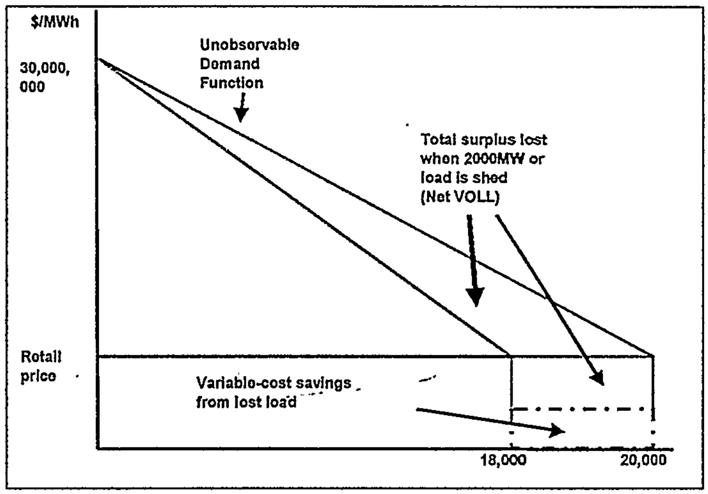
Thus, according to the Simple Model of Reliability a policy that induces investment when $D_{LS} < FC_{Peak} < V_{LL}$ will be optimal. There exist two regulatory approaches to setting prices that will attract an optimal level of investment. By setting price equal to the average value of lost load, V_{LL}, competitive suppliers will have an incentive to invest in an optimal level of generating capacity. This regulatory intervention is known as value of lost-load pricing (VOLL pricing). Markets that do not use VOLL pricing usually have an operating reserve requirement backed by high prices. These operating reserve (OpRes) prices are often greater than needed to entice operating reserves from the local market. Thus, OpRes prices serve to both, compete with other control areas for reserves and to induce investment in generation.

3.3.1 Value of Lost-Load Pricing

As has been suggested previously, contemporary power markets with inelastic demand would grossly underinvest in generation if there were no regulatory price setting mechanisms in place. VOLL pricing recognizes that the system operator must purchase power on behalf of load whenever demand exceeds supply. It instructs the consumers to pay V_{LL} if some load has been shed. Ignoring market power and the risk of extreme price swings,VOLL pricing produces exactly the right level of installed capacity, which minimizes the sum of the costs of capacity and lost load. Implementing VOLL pricing requires a regulatory determination of V_{LL} because markets cannot specify the value of additional power due to the demand-side flaws. V_{LL} defines the height of the aggregate price spike, while the duration is decided by the timing of this price setting (Stoft, 2002, 155-164).

In the most critical circumstance, when supply has reached its maximum and load must be shed, the system operator must decide how much to offer for additional supply. The standard regulatory choice is to pay the cost of additional generation. The market approach is to offer the value that customers place on not being cut off. This value might be $\$10,000/MWh$ while the cost of last unit of produced power is only $\$500/MWh$. If the market is perfectly competitive, it is cheaper to offer $\$10,000/MWh$ and pay this much whenever load is actually shed. This is the price determined by the intersection of the demand and supply. Setting the price of energy in the spot market to this price whenever load has been shed is VOLL pricing. This result depends on the ability to prevent market power, on risks of extreme prices being costless and on the assumptions of the Simple Reliability Model.

To apply VOLL pricing it is necessary to estimate the value of lost load. However, since most customers do not respond directly to real-time prices, no information on the value of lost load exists and the estimates are highly inaccurate. Thus, VOLL pricing sets the regulated rather than market price. Since in case of inevitable blackouts, a consumer that values its power at $\$10,0000/MWh$ is as likely to be not served as one whose willingness to pay for power does not exceed $\$200/MWh$, the costs of load shedding are very large. (For example, the value of electricity to someone using a home oxygen machine may be much higher than to someone else using a dishwasher; but blackouts are unable to discriminate between one use or the other.). Although VOLL pricing is inefficient relatively to market outcomes that could rely on real demand elasticity, under the Simple Reliability Model, it is said to be optimal as long as the demand-side flaws cannot be eliminated.



Most consumers cannot respond to daily price fluctuations and their short-run demand is unobservable. If consumers were charged real-time prices and could respond to them, they would probably use much less power at sufficiently high prices. Figure 6 shows that when power is shed, the total consumer surplus is reduced (the area under the unobservable demand curve). When load is shed, consumers are disconnected regardless of the value they place on power. Assume that the demand function is scaled back by 10%, then the total value of lost load is $\$15,000/MWh$ ($= \frac{\$30{,}000{,}000/MWh}{2000MWh}$).

VOLL Pricing Model:

The reduction in consumer surplus caused by $1MW$ of shed load is V_{LL}. When load shedding is optimal, a reduction of installed capacity would cost consumers as much in lost value as would be saved by the decrease in capacity.

$$V_{LL} = \frac{FC_{Peak}}{D_{LS}} \tag{1}$$

$$D^{*}_{LS} = \frac{FC_{Peak}}{V_{LL}} \tag{2}$$

Recall from the earlier section that the long-run equilibrium condition for investment in peakers is

$$FC_{Peak} = R_{Spike} \tag{3}$$

$$FC_{Peak} = V_{LL} x D_{LS} \tag{4}$$

$$D^{E}_{LS} = \frac{FC_{Peak}}{V_{LL}} \tag{5}$$

From (2) and (5) we can infer that equilibrium and optimal duration of load shedding, (D^{E}_{LS}) and (D^{*}_{LS}) are the same. Thus, by using the results of the Simple Model of Reliability, VOLL pricing is shown to be optimal, meaning that the right level of generation investment and hence reliability will be achieved.

3.3.2 Operating Reserves Pricing

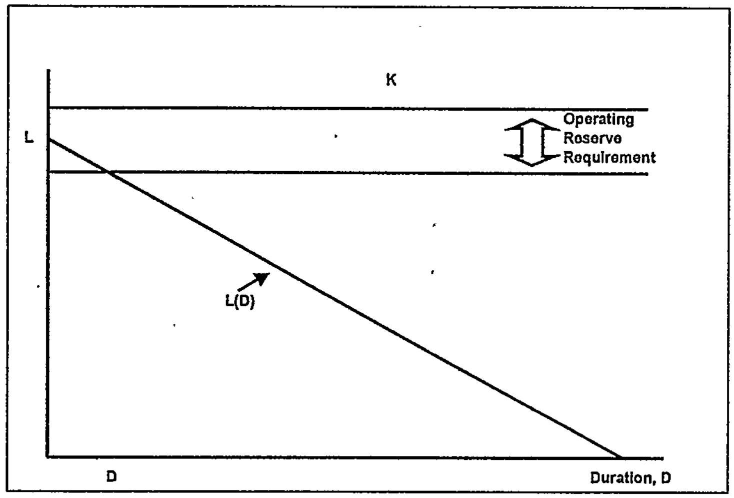
In order to pay for the fixed costs of capacity, it is necessary for prices to spike. The highest price should occur when load has been shed, but even then the system operator should not pay more than what the power is worth. Research estimates that such price can be found in between $\$1000/MWh$ and $\$100,000/MWh$ (Stoft, 2002, 112). The Australians estimate V_{LL} to be approximately $\$16,000$ but cap their price at about $\$10,000$ (Stoft, 2002, 112).

In the United States and Western Canada, system operators take a different approach. In compliance with NERC guidelines, they set operating reserve requirements which cover regulation, spinning and non-spinning reserves which together amount to about 10% of load. Instead of waiting until load must be shed to raise price, a shortage of operating reserves is deemed to be sufficient reason to pay whatever is necessary. This results in high prices whenever demand exceeds about 90% of total available supply which occurs far more often than load shedding. Thus, the North American reliability policy determines a much longer duration for price spikes (Stoft, 2002, 166).

Operating Reserves Pricing Model:

The following model will aid to show that OpRes pricing will induce the optimal level of investment. The model requires demand and supply sides, regulatory rules and the market equilibrium condition.

The break-even condition for generation investment is that expected short-run profits equal fixed costs. Higher profits will attract new investment, while lower profits will put a stop to investment. Investment increases the level of installed capacity, K, relatively to load. Thus, the short-run profits depend on K.



$$L_g = L_g(D) = L_{\max} - \alpha D \quad (1)$$

Equation (1) is the load duration curve modified to take account of generation outages.

When L_g+ $OR^R < K$, there is no shortage of operating reserves and P^R is zero. However, when L_g+ $OR^R > K$, then P^R is set to the price cap, P_{cap}, and there is a price spike. The duration of a price spike, D_{PS} is found from

$$L_g(D_{PS}) + OR^R = K \quad (2)$$

During a price spike short-run profits, SR_π, are given by P_{cap} times the duration that the market price is at the cap. The short-run profit function of a peaker is given by

$$SR_\pi(K) = D_{PS}(K) \times P_{cap} \quad (3)$$

and

$$SR_{\pi}(K^E) = FC_{Peak} \tag{4}$$

so that (4) determines the long-run equilibrium value K^E.

From (1) and (2), we can solve for $D_{PS}(K)$:

$$D_{PS}(K) = (L_{\max} + OR - K)/\alpha \tag{5}$$

From (5) and (3), we can find short-run profit function:

$$SR_{\pi}(K) = \frac{(L_{\max} + OR - K)xP_{cap}}{\alpha} \tag{6}$$

From (6) and (4), we can solve for K^E (the level of K that produces expected short-run profits that just cover fixed costs):

$$K^E = L_{\max} + OR - \alpha FC/P_{cap} \tag{7}$$

From (7) & (5) can find D_{PS},

$$D_{PS}(K^E) = \frac{FC_{Peak}}{P_{cap}} \tag{8}$$

(7) and (8) are solved based on the two policy parameters, P_{cap} and OR^R. It can be useful to find one of the policy parameters given a desired level of installed capacity, K^*. Thus, by solving (7) we obtain:

$$OR^R = K^* - L_{\max} + \frac{\alpha FC_{Peak}}{P_{cap}} \tag{9}$$

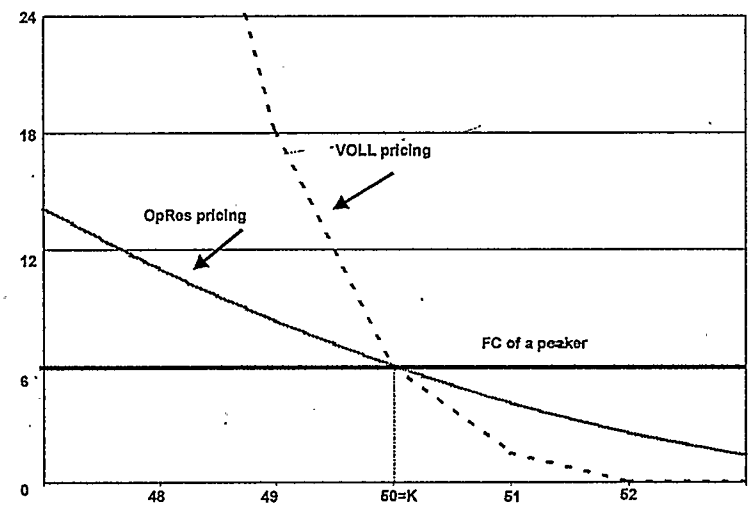
The optimal level of K can be obtained with a continuum of different policy options ranging from extremely high price caps and low OpRes requirements to low price limits and high OpRes requirements. To illustrate, consider a market where price of reserves, P^R, is equal to $\$250/MWh$, $\alpha = 50,000$, $FC_{Peak} = 10$, $VC_{Peak} = 2.5$ $L_{\max} = 8,000$ peakers are earning short-run profits above $\$150/MWh$ (they cover their fixed costs more than 20 times over). Suppose the target K is 20% above peak load. Setting OR^R to 200% of peak load will guarantee that a system is always short of reserves and peakers are earning over $\$150/MWh$ of profits. This is far more than needed to induce the desired K level. If too much investment can be induced with an extreme OR^R, then the right amount can be achieved with a more modest OR^R.

From equation (9), we can infer that as long as the product of height and duration equals fixed costs, the OpRes pricing will induce the optimal level of investment. Consequently, only the secondary effects of the policy (i.e. high, short-duration spikes or low, long-duration spikes) can be used to choose between them. Thus, a $10,000 price spike that occurs once every three years and cause a near bankruptcy will grab more headlines than many $300 price spikes that occur regularly throughout the summer.

3.3.3 VOLL Pricing vs. OpRes Pricing

Under VOLL pricing the system operator sets the spot-market price to V_{LL} whenever the augmented load, L_g, exceeds installed capacity, K. OpRes pricing approach sets the price to P_{cap} whenever operating reserves fall below the operating reserves requirement, OR^R.

In order to compare the two regulatory price setting mechanisms we need the profit functions for the peakers. Once calculated they will reveal the equilibrium level of installed capacity and give some indications of the market's riskiness and possibility of exercising market power.



A pricing policy that relies on a higher, shorter-duration price spike to induce more investment is identified by a steeper short-run profit function. Thus, as Figure 8 shows, VOLL pricing generates a much steeper profit function. From Figure 8 we can infer that although the slope of the profit function under two regulatory policies are different, VOLL and OpRes pricing produce an optimal level of investment in generation capacity.

A short-duration aggregate price spike causes much more year-to-year variance in short-run profits than does a long-duration aggregate price spike, thus an OpRes pricing scheme seems to generate less risk associated with the recovery of fixed cost investment and is said to be less conducive to the exercise of market power.

Stoft (2002) examines how short-run profits fluctuate under the two regulatory price settings. He generated a 40-year sequence of price-spike revenues using a Monte-Carlo simulation and found out that during the first twelve years peakers cover none of their fixed cost under the VOLL pricing. Under the OpRes pricing peakers are able to recover 80% of their fixed cost even in normal years.

However, the biggest drawback of VOLL pricing is its inducement of market power. Recall that VOLL pricing is associated with a very high price cap. First, a high cap allows a much greater increase in profits from the exercise of market power. A supplier is able to withhold some of its capacity and force load shedding, in which case the system operator is prepared to pay V_{LL}. Furthermore, a high price cap is accompanied by a short duration price spike, otherwise it would produce enormous excess profits. Also, the percentage increase in price-spike duration is greater when applying a fixed amount of capacity withholding to a short-duration price spike, this is a property of diminishing returns to load duration, i.e. for every MW decrease in capacity, the load duration increases by a smaller percentage than for the previous decrease.

4 The Alberta Electricity Market

Although there has emerged a standard model for restructuring electricity industry, each jurisdiction is so different that no two electricity markets are exactly alike. The Alberta market follows the guidelines of the North American Electric Reliability Council (NERC) in order to maintain the reliability and security of the system (i.e. the amount of reserves it must buy in any given hour) but has a free hand in the design and market architecture. It creates regulatory institutions and sets the rules regarding the market participation as it sees fit.

This section describes the origins and the evolution of the Alberta energy and ancillary services markets, their rules and the regulatory institutions that oversee the operations of the two markets and the behaviour of the participating generators. The following subsections provide an in-depth discussion of both the Alberta energy market and the ancillary services market, their rules, regulations, the means of procuring energy and ancillary services as well as the dispatch process.

4.1 Electricity Restructuring in Alberta

Economic theory predicts that in the long run the availability, flexibility and cost characteristics of the generation units and loads will offset the likely inefficiencies introduced into the market by the short run inadequacy of the system control/dispatch process (Ruff, 2002, 10). Thus, every transformed electricity market attempts to adopt a structure that will facilitate an integrated system control/spot pricing/congestion management process .

However, it would be both premature and presumptuous to assume that implementation of the aforementioned process is an easy task. Since every electricity market is unique there doesn't exist a uniform guideline for an efficient market design and what seems to be effective in one market might not be fully applicable to another. It should also be noted that as markets evolve, the design must be adjusted to accommodate new conditions prevailing in the markets.

The enactment of the Electric Utility Act (EUA) in 1995 was the fundamental step towards the restructured electricity market in Alberta. The EUA outlines the market architecture essential for the Alberta deregulated electric environment. It has provided open access to generation units as well as established centralized institutions responsible for the efficient operations of the competitive market. At the foundations of the new market lies the idea of mimicking as closely as possible the economic dispatch process used by the integrated monopoly, which determines real time operations that minimize the cost of meeting demand given real time conditions and system security constraints including transmission constraints.

At the centre of the current structure in Alberta is the Power Pool of Alberta (referred to as either "the Pool" or "the Power Pool"). The Pool oversees the System Controller (the SC) who is responsible for real time physical operations and a Pool Administrator (the PA) that operates the real time market. The Transmission Administrator (the TA) is a separate entity overseeing planning and operating functions for the grid, determining the costs of losses and congestion as well as procuring the system support services through the external markets (such as Watt-Exchange and OTC).

Functions of the SC and the PA are independent from each other yet in the real time their operations are integrated in essential ways. Those wishing to purchase and sell electricity submit their bids and offers, respectively, to the real time market a day in advance. The PA constructs the unconstrained dispatch schedules, calculates the pool price for each hour of the next day and passes it onto the SC. The latter updates the PA's estimates with later information on demand and generator availability as well as the system support services volumes, grid conditions and system security constraints and subsequently determines an efficient economic dispatch (in accordance with the system security and generator dynamic constraints). Finally, the PA uses the operational and the updated market information to establish the *ex post* unconstrained pool price .

At the beginning of the restructuring process, Alberta's transmission grid was owned partially by private and public companies. In order to implement the open access transmission principle in the electricity market, the EUA created the TA which determines the standard tariff-setting as well as planning and operational functions for the entire transmission system.

The TA coordinates grid outages with the grid owners, provides the SC with both dispatch guidelines that intend to reduce losses and the information on congestion status for the upcoming week. Another of the TA's responsibilities is to procure the system support services that are later dispatched by the SC.

When making a transition from regulation to competition, a great emphasis should be placed on the market surveillance and the creation of agencies designed specifically for monitoring the competitiveness and efficiency of electricity markets (Competition Bureau, 2002, 12). In Alberta, the Market Surveillance Administrator (the MSA) is the agency responsible for monitoring and analyzing the rule, behaviour and practices of the regulatory regime. The MSA monitors market participants in order to determine if their strategies are consistent with the competitive behaviour, and its primary focus is on seller behaviour and seller concentration in generation, ancillary services and retailing. The MSA has the power to investigate and consequently deter any actions that creates, enhances or maintains market power in the AIES. Once the problems are identified, the MSA doesn't necessarily directly address the concerns, but may refer them to the agencies that are capable of effectively dealing with them .

4.2 The Energy Market in Alberta

All electric energy traded in the province must be bought and sold through the Power Pool which sets an hourly market price for all power traded. The market price for electricity is calculated by matching supply with demand. The market works on day-ahead basis, with Power Pool members submitting offers to sell and bids to purchase energy for the following day. The information gathered from the day-ahead market allows the Power Pool to forecast the electricity supply, demand and provide the market-clearing price for the following day.

Generation units place offers to supply hourly blocks of energy at specified prices for a 7-day period with the offer price for the first trading day fixed. Market participants wishing to purchase electricity place bids to buy blocks of energy for the following 6 business days with prices fixed for the next day. The Pool ranks the offers from the least to the most expensive and determines the unconstrained merit order to forecast pool price for each hour of the next day. The offer price of the marginal generation unit required to meet the demand in a given hour defines the pool price for that hour. Under this pricing scheme, suppliers bid approximately their marginal costs for energy in each of the blocks of power they offer. The suppliers know that on their accepted bids they are allowed to pocket the difference between their incremental costs and the market clearing price (which is a necessary contribution towards recovery of their fixed costs). In case of bids being rejected, the suppliers are better off since they don't have to commit themselves to sales at prices that fail to cover their avoidable costs. Consequently, the power is supplied at the minimum cost, at each point in time. Furthermore, as long as competition is effective, any generator that withholds power in hope of raising the market-clearing price and earning monopoly profits will find itself displaced by competitors bidding their own, lower marginal costs.

4.3 The Ancillary Services Market in Alberta

The standard prescription for restructuring electricity market requires that the monopolistic wire segments of the industry remain regulated and that access to those segments is non-discriminatory. The regulatory scrutiny in Alberta is accomplished by creating the Transmission Administrator whose duty is to ensure that anyone can participate in the Power Pool as long as they satisfy the technical requirements set out by the Pool. Besides scheduling the transmission access for energy traded in the Power Pool, the TA is responsible for maintaining the reliability of the entire Alberta Interconnected Electricity System (AIES). For that purpose, the TA operates an ancillary service market where additional MWs of power are procured through a competitive bidding process. In addition, the TA uses long term transmission "must run" contracts as well as other forms of long term bilateral agreements to ensure the security and adequacy of the AIES.

The Alberta Ancillary Services market in its current form was established on July 3, 2001 with the first bids being submitted on June 25, 2001. Prior to adopting the prevailing market design, the Transmission Administrator (the TA) decided that the procurement of the system support services (the SSS) should embody the concept of the level playing field and that the SSS should be obtained competitively whenever possible. Furthermore, the owners of generators and loads connected to the transmission system were to be subject to the terms and conditions put forth in the Technical Requirements for Connecting to the Alberta Interconnected Transmission Grid. In its policy on procurement methods in the post-2000 electricity market, the TA noted that the potential for the short run competitive procurement of reactive power and black start capability is low, so that an optimal method of acquiring those services is via bilateral contracts with individual generators.

Initially there were to be four competitively procured system support services in the Alberta markets: regulating reserves, spinning reserves, non-spinning (supplemental) reserves and replacement reserves. The first three correspond to services defined by the North American Electric Reliability Council (NERC) while the forth, replacement reserves, was defined to satisfy the Western System Coordinating Council (WSCC). The TA derives its SSS standards from both the WSCC Minimum Operating Reliability Criteria and the NERC Criteria to the extent they are applicable to the AIES. The TA has the right to adjust the SSS standards temporarily to take into account variations in the system conditions, real-time dispatch constraints, contingencies and voltage and dynamic stability assessments. (Those accommodations in the SSS standards can be arranged subsequent to consultations with the System Controller.) (ESBI, 2000, 4-5).

4.3.1 Regulating Reserves

Regulating reserves are used to instantaneously balance supply and demand in response to the continuous fluctuations in demand and available generation as well as to aid in maintaining the scheduled frequency of the interconnection (which, in Alberta, is 59.9 Hz). Regulating reserves are procured to satisfy both: the minimum system regulating requirement as well as the high system demand ramps. Only generation capacity that is already up and running, and synchronized with the grid is eligible to supply regulating reserves (regulating reserves that participate in special "remedial action schemes" (RAS) may not be eligible to provide regulating reserves while RAS is in effect.). Regulating reserves can be increased or decreased instantly through automatic generation control (AGC). The response time to the AGC control signal cannot exceed 28 seconds. Regualting reserves resource must be stable at any dispatch level within its regulation range. Therefore, generator providing the regulating reserves must be able to hold the level of real power set by the last control signals +/- a real power deadband, where the deadband is +/- 5% of the maximum regulation range or +/- 1MW, whichever is greater. Any facility planning on bidding into the regulating reserves market must keep the current levels of availability and capability of the generator/ load through the Power Pool's electronic trading system (the ETS) interface for asset characteristic. Any changes in the prevailing status of availability and capability must be recorded via the ETS and the SC has to be notified about any of the restatements. When making the adjustments in the regulating reserves, the provider must state which of the following events made the restatement necessary: 1) local emergency at the Ancillary Service Resource, 2) forced outage of the ancillary service resource, 3) unplanned outage of the ancillary service resource, 4) planned availability of the ancillary service resource. Communicating the necessary restatements to the SC aids the latter to appropriately and optimally accommodate the volume of the regulating reserves in real time and sustain the security and adequacy of the AIES (ESBI, 2000,1-6).

The detailed disclosure of information regarding the adjustments to the availability and capability of the resource provider allows the SC to use the right generators in the right amount at the right times in order to minimize the total cost of physical operation.

Each successful supplier must be able to operate continuously at either the high limit or the low limit of the regulation range for 60 minutes while providing the regulating reserves. Thus the TA requires all of the potential regulating reserves providers to submit both the high and the low limits associated with each regulating range offered. (These limits are intrinsic to the physical characteristics of the generators and are specified by the generator manufacturers.) If this guideline was not implemented and closely monitored the system's security would be jeopardized leading to an imbalance between demand and supply and subsequently to the deviations in the system's frequency.

The TA needs sufficient generating units that are immediately responsive to AGC so it can comply with the WSCC and the NERC criteria for control performance by continuously balancing generation to meet the deviations between supply and demand in a Control Area. The TA has determined that the percentage of the regulating reserves it requires in the day-ahead market is equal to 120 MWs (based on the operating requirements). Currently all of the regulating reserves are procured within the Alberta Control Area.

4.3.2 Operating Reserves

The TA maintains the sufficient volume of operating reserves that is in accordance with the WSCC standards. The operating reserves consist of the spinning and supplemental reserves. When defining the minimum level of operating reserves, the TA must account for the 500kV Interconnection with BC Hydro.

If BC Hydro is in service, then the operating reserves are found as the sum of regulating reserves (RR) and contingency reserves (RC), where RR is the sufficient spinning reserve, immediately responsive to AGC to provide sufficient regulating margin to meet NERC's control performance criteria. RC is an additional amount of reserves sufficient to reduce the area control error to zero or to its pre-disturbance level within 15 minutes of the contingency and of which at least 50% must be spinning reserve.

The required volume of RC is equal to the greater of either (1) the import level of the BC- Alberta Interconnection less any armed import load RAS, less load armed at 59.9 Hz under-frequency load shedding with no intentional time delay *or* (2) the sum of 5% of firm load responsibility served by hydro generation and 7% of firm load responsibility supplied by the thermal generation.

If BC Hydro is out of service then the only adjustment is made with respect to the required volume and (1) is now equal to the largest contingency (in Alberta- 395MW) plus the import level on the BC interconnection minus the export level on the BC interconnection .

Example 1 *BC Hydro Tie-Line Out of Service*

500kV BC tie is out of service

0 MW Import or Export Conditions

System load 4793 MW

Largest single contingency 395 MW

Imports 0

Exports 0

Firm load responsibility 4293

5% loaded Hydro 16 MW=5%*321 MW (assumed)

7% loaded Thermal 278 MW=7%*(4293-321)

The contingency reserve requirement is determined by the largest single contingency criteria – 395 MW while a minimum of 50% of the total contingency reserve requirement must be provided by spinning reserves.

Example 2 *BC Hydro Tie-Line in Service:*

500 kV BC tie in-service

0 MW Import or Export Conditions

System load 4793 MW

Largest single contingency 395 MW

Imports 0

Exports 0

Firm load responsibility 4293

5% loaded Hydro 16 MW

7% loaded Thermal 278 MW

The contingency reserve requirement would be 294 MW (16MW +278 MW) while a minimum of 50 % of the total contingency reserve requirement must be provided by spinning reserves.

Spinning Reserves: Spinning reserves are used to supply the requirements for load variations and to replace generating capacity lost due to forced outages of generation or transmission facilities. Spinning reserves is the generation capacity that is already up and running with additional capacity that is capable if ramping over a specified range within 10 minutes after receiving a directive. The supplier should be able to sustain the delivery of the spinning reserves for the lesser of (1) a period of 60 minutes from the time of receiving the directive or (2) the period of time until the SC cancels the directive.

The TA requires any generator bidding into this market to provide at least 10 MW of spinning reserves. When offering the spinning reserves to the market every provider must ensure that the maximum volume of spinning reserves is within the range of maximum and minimum real power capacity range of the generation unit. As with regulating reserve, a generation unit that participates in the RAS may not be eligible to provide the spinning reserves while the RAS is in effect.

Provision of Spinning Reserves from External Sources: A generation unit that is willing to offer spinning reserves that is external to the Alberta control area must be located in the jurisdiction of the WSCC. The external spinning reserves resource (ESRP) obtains its directive to deploy the specified volume of spinning reserves through the host control area (HCA) in which the supplier is located.

When the ESRP is deployed an interchange schedule across synchronous ties must be established, in this case between Alberta control area and the HCA on the Alberta-BC Interconnection. The minimum required volume of spinning reserves to be provided is 10 MW. However, the actual level of external spinning reserves that will be deployed must be adjusted in such a way that the frequency of 59.9 Hz is recovered and maintained at all times (if the level of contingency reserves are established based on the loss of the Alberta-BC interconnection). When the 500kV interconnection with BC Hydro is out of service, none of the external spinning reserves will be used by the SC. Prior to a directive, the ESRP must confirm that the HCA is capable of maintaining the deployment of the spinning reserves for up to 60 minutes following the directive. The ESRP is also obliged to validate that the HCA will accept the SC dispatch to reactivate and reposition the ESRP between 10 to 60 minutes following the SC directive .

Supplemental Reserves: Supplemental reserves is the generation capacity that is available but not running (spinning). To meet the supplemental reserves requirements, a facility's capacity must be able to synchronize and ramp to a specified volume within 10 minutes. The volume of the real power change within those 10 minutes must be somewhere between the minimum 100% and the maximum of 110% of the directive volume. Supplemental reserves can be supplied either by the generation units or by load, yet the technical specifications set out by the TA are the same regardless of the type of the provider.

A generation unit must be able to provide at least 5MW of supplemental reserves. A provider that is scheduled to supply supplemental reserves must be capable of running for up to 60 minutes following the directive. If after those 60 minutes the SC has not rescind the directive, then the provider may adjust its real power level to the one it had prior the directive. Similarly to spinning reserves, the supplemental reserves are used to balance load and becomes a substitute for resources that suffered forced outages .

4.3.3 Summary of the Reserves Characteristics

(Ranked in the ascending order based on the quality)

Ancillary Service	Resource Type	Ramp Time	Usage of Resource
Regulating	Capacity capable of responding to the SC signal instantenously through AGC	15 minutes	To continously balance load fluctuation and the maintain the AIES frequency
Spinning	Spinning Capacity	10 minutes	To supply requirements for load variations and to replace capacity lost due to forced outages
Supplementa	External generation and load, excess spinning	10 minutes	To serve as an additional energy reserve which can be accessed in case of a shortfall

4.4 Procurement of the System Support Services

The TA procures most system support services through the electronic exchange, Alberta Watt Exchange Limited (Watt-Ex) that has replaced the bilateral acquisition process between the TA and the suppliers. Currently, 90-93% of all the ancillary services are being procured through Watt-Ex, while the residual volume is obtained by the TA through "over the counter" contracts.

Watt-ex operates a "day-ahead" market where participants submit bids and offers for tradable instruments that allow them to trade contracts for multiple hours of the succeeding day while using a single transaction. Currently, Watt-Ex offers four tradable instruments: (1) Base-load instruments that allow trading the hours from 1 to 24 in a single day, (2) Peak-load instruments used in the hours from 8 to 23 in a single day, (3) Off-peak instruments that handle the trade from hours 1 to 7 and 24, and (4) Super-peak instruments that trade the hours from 17 to 18 in a single day. Trading of the above instruments occurs during 5 business days prior to the performance of the SSS between 7:00 am and 3:00 pm. Since the TA procures the SSS in three portfolios Active, Standby and Backup encompassing the regulating, spinning and supplemental Reserves, the bids for each SSS must be submitted in the following manner: 1) active regulating reserves before 11:10 am, 2) active spinning reserves before 11:20 am, 3) active supplemental reserves before 11:30 am, 4) standby regulating reserves before 1:10 pm, 5) standby spinning reserves before 1:20 pm, and 6) standby supplemental reserves before 1:30 pm.

Market participants can submit their bids and offers into any or all six of the SSS; however they can sell only one type of service of active or standby reserves per hour. Thus if a generation unit is selected to provide a higher quality service, that unit is not available to the markets with lower quality. For example, in case of successful active spinning reserves sales, the generation unit can either provide more of the active spinning services or standby spinning reserves, yet it is not allowed to supply other types of services included in the active portfolio. All bids and offers must contain a capacity price, an energy price for the real time energy market and quantity.

The procurement of the SSS, like the bids, is conducted in a sequential order according to the quality of the SSS. Thus, once the demand is estimated for each of the SSS, the auction for the active regulating reserves is conducted first succeeded by the auction for active spinning and active supplemental. The price of active portfolio is set based on the equilibrium pricing where the market price is determined by taking the average of the highest accepted offer and the lowest accepted bid. The standby markets operate on the pricing model similar to that of a forward option. There are two price components; a premium price for capacity reservation and an activation price if a supplier is called on to provide energy. Typically, when a probability of activation is high, a low activation fee is offered coupled with a high premium. Thus, the premium is paid regardless of whether the service is actually delivered while the activation price is paid by the TA if and only if the standby service becomes activated. The rationale for a two tier pricing of the standby portfolio is attributed to the fact that under current market design suppliers take all the risks associated with the provision of standby portfolio resources (The TA is a sole buyer of the ancillary services).

In order to ensure a fair and orderly market, Watt-ex decided to implement the bid and offer "lock-down". Five minutes prior to the close of each market existing bids and offers cannot be withdrawn. During that time-frame the bids can be increased either in price or in volume. Similarly, the offers can be reduced in price and increased in volume. Additionally new bids and offers can be submitted during the lock-down. Thus, the lock-down mechanism can be compared to the hour-ahead market which gives the participants an opportunity to make adjustments based on their day-ahead schedule.

4.5 Portfolio Dispatch

As discussed above, the TA procures the SSS in three portfolios: active, standby and back-up, that consist of the regulating, spinning and supplemental reserves. The active portfolio is used to meet the requirements of the AIES under the normal operating conditions. When the resources available in the active portfolio are incapable of providing the required volume of the SSS, the TA calls on the generation unit from the standby portfolio. The purpose of the back-up portfolio is to contribute the SSS resources if the volumes committed under both the active and the standby portfolios cannot balance supply and demand. It should be noted that the need to dispatch resources from any portfolios other than the active portfolio may trigger sanctions under the procurement contracts. Thus the reasons for deploying resources from the standby and back-up portfolios must be well documented.

Resources from the active portfolio are always fully dispatched unless such dispatch would put the system security at risk. If a contingency occurs that renders the deployment of standby resources necessary, then the standby portfolio is deployed in the merit order of increasing priority. The same set of dispatch rules holds for the back-up portfolio. Each resource in the three portfolios is defined as either flexible or non-flexible, meaning it can be dispatched up as a whole block of bid-in capacity or only as a small portion of the capacity bid.

When levels of active regulating reserves are insufficient to satisfy the TA requirements, the additional regulating reserves will be dispatched up first from the standby portfolio and if those extra volumes still do not balance the market then the regulating reserves from the back-up portfolio are called up for delivery.

When the volumes of active spinning reserves are too low then the SC dispatches additional spinning reserves according to the following order of priority: 1) standby spinning reserves, 2) standby regulating reserves if the standby spinning is not adequate, 3) if the spinning reserves are still below the required level, then the back-up spinning is being dispatched, 4) if spinning reserves are still insufficient the regulating reserves from the back-up portfolio are used.

The same set of rules apply to procurement of additional supplemental reserves if their volume available in the active portfolio is too low. Firstly, the SC dispatches the supplemental or spinning from the standby portfolio. If that is not enough, the standby regulating reserves are used up. When the supplemental reserves are still too low, the SC calls on the supplemental and spinning reserves from the back up portfolio which is followed by the regulating reserves in the back up portfolio .

Example 3 *Dispatch of Reserves*

Assume that there are three generators with a 400 MW capacity each. Two of them, A and B participate in the regulating reserves market and successfully bid in 80 MW each. 160 MWs of capacity is all that the TA procured the day before. Presently, A and B are operating at a 320 MW capacity while the third generator, C operating at 400 MW goes down. In order to restore the system reliability, the two generators, A and B will increase their capacity to 400 MW and the residual will be supplied from the standby regulating portfolio.

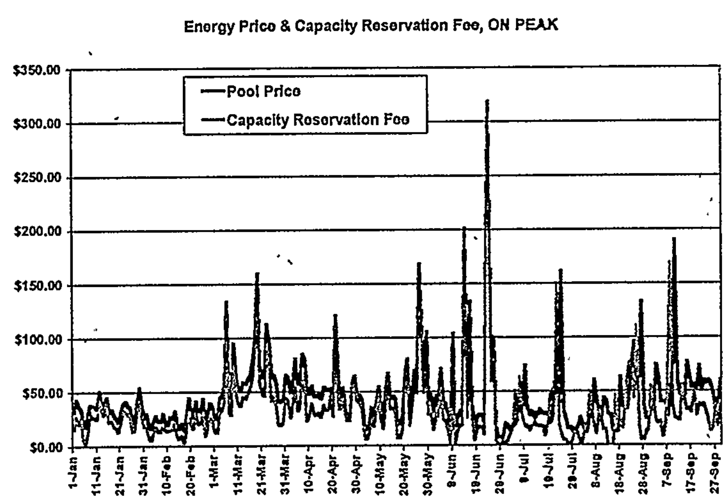
The two generators will receive the "active price" for the additional MW, while the new generator that is being called on will be paid the premium and activation fee agreed upon in advance.

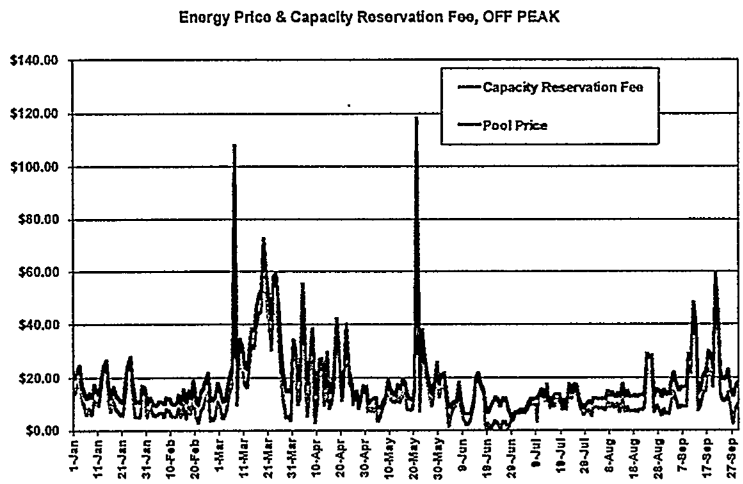
5 Data

This chapter provides a brief description of the data utilized to test the degree of competitiveness of the regulating reserves market.

I investigate the period January 1, 2002 to September 30, 2002 using the Watt-Ex daily energy prices and the daily capacity reservation fees (referred to as fee). The data set was generously donated to me by Mr. Doug Andrews, the CEO of the Alberta Watt Exchange Ltd. Sample size used in this thesis is relatively small but unfortunately all that was available. Prior to January 1, 2002 not all of the required information was recorded.

I created two data series: the price and the fee for the on-peak period (hours 8 to 23) and for the off-peak period (hours 24-7). Plots of the price series appear in Figures 9 and 10.





Although there might be seasonality in my data set, I do not formally test for it due to short sample period.

Energy prices in Alberta were very volatile between January 1, 2002 and September 30, 2002. This statement holds regardless of the series at hand. The maximum price during the on-peak period was $318.50 while the lowest equaled $7.56. This compares with the maximum of $118.26 and the minimum of $3.72 in the off-peak series. The average prices during the on-peak and off-peak periods were $47.24 and $18.90, respectively. While the average value may be distorted by extreme values, the median price may show a better picture of price distribution. The median price was $39.52 for the on peak series and $14.85 for the off peak series.

Capacity reservation fee (i.e. the fixed fee paid to generators for reserving capacity) statistics also differ depending on the period at hand, with higher statistics for the on peak and relatively lower for the off peak period. The summary of the price and fee series statistics is presented in Table 2. All skewness statistics are positive indicating that the series are spread to the right. The kurtosis statistics are all greater than 3, thus the distributions are more outlier-prone than the normal distributions. The correlation coefficients are 0.803 in the on peak period and 0.981 in the off peak period. Thus, the two series are linearly dependent.

	ON PEAK		OFF PEAK	
	Price	Fee	Price	Fee
Average	47.24	34.10	18.9	13.54
Median	39.52	26.72	14.85	9.72
Minimum	7.56	0	3.72	0.09
Maximum	318.5	307	118.26	112.86
Standard Deviation	34.56	33.73	13.48	12.72
Skewness	3.33	3.64	3.56	3.87
Kurtosis	17.40	19.98	18.34	22.26
Correlation Coefficient	0.803		0.981	

6 Competitiveness in Ancillary Services

Many generators can choose whether to sell less energy and supply more reserves or vice versa, so there is some arbitrage between the energy and the ancillary services markets. If the markets were well integrated then in the long-run generators would be indifferent between the choice of the market since the profit opportunities would be converging towards the same value. The first portion of this section describes how generators decide which market they want to participate in. The second element of this section provides a mathematical formula (based on modeling above) for calculating the expected profits in two markets. It further provides estimates of the excess profits in the regulating reserves market and finds that they are significantly above zero. Thus, there is some evidence suggesting that the regulating reserve market is not operating as competitively as the energy market.

6.1 Efficient Market for Ancillary Services

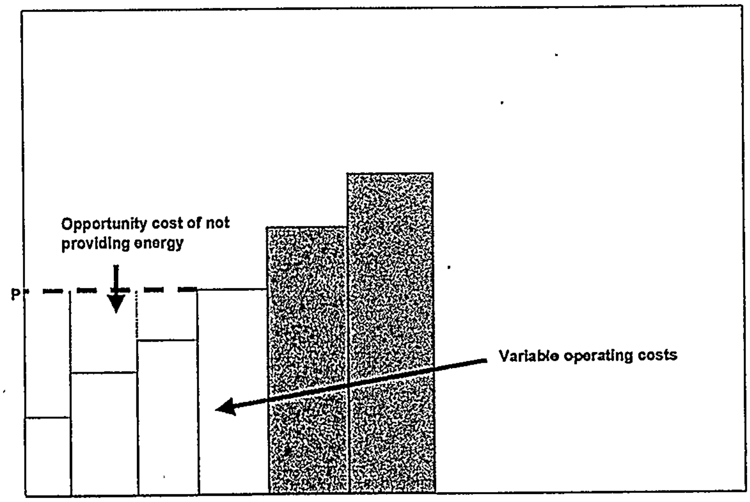
When creating markets for ancillary services it is essential to understand the relationship between generating electricity and providing ancillary services and the options the plant owner faces when selling into the two markets. The manner in which ancillary services are purchased affects not only prices for ancillary services but also the prices in the energy markets. At any point in time, the maximum amount of output a generator can provide is fixed at the capacity of the unit. This capacity can be divided between energy and ancillary services; hence a generating unit can provide one or the other, but not both at the same time, from the same block of capacity. Since ancillary services and energy are substitutable products, generating capacity allocated to supply energy is not available to supply ancillary services. Thus in the short run, how ancillary services are bought will affect the amount of capacity available which in turn will impact the prices in the energy market .

6.1.1 Cost of Providing Ancillary Services

Regulating and spinning reserves can only be provided by the generators that are synchronized to the grid and producing at least some minimum level of output (referred to as on-line generators). Thus the decision to operate a unit for ancillary services cannot be isolated from operating the unit to produce energy.

A generating unit selling reserves must forego the profits from generating energy from the same portion of capacity. Hence, the cost of supplying ancillary services is the opportunity cost of not providing energy. Overall, we would expect prices for energy and ancillary services to move in tandem.

For example, when the price is \$40/MWh, a generating unit with variable cost of \$30/MWh has an opportunity cost of selling ancillary services equal to \$10/MWh (which is the profit it would make on selling into the energy market). The minimum price a generating unit would accept for supplying ancillary services would be \$10/MWh. At any price below \$10/MWh it would prefer to provide energy and at any price level above \$10/MWh a generating unit would sell more reserves.



In order to examine how efficiently a market operates, one can compare the actual prices in the market with the expected prices in the efficient market. Economic theory states that the cost of providing reserves reflects the opportunity cost of not supplying energy and that the prices in the ancillary services market should equal to the cost of a marginal supplier. Thus, the expected prices in the ancillary services markets should equal the marginal opportunity cost of foregone energy sales.

Provision of Regulating Reserves in Alberta: The decision on whether to participate in the ancillary services auction or to supply energy to the Power Pool is made based on the opportunity cost. Firms being able to forecast the expected demand and supply can calculate the expected future profits in two markets. If the estimates of expected profits are equal, then firms are indifferent between providing energy and ancillary services. When calculating the opportunity cost of not providing ancillary services several formulas are being used in order to reflect the true costs of different ancillary services.

Pricing Regulating Reserves:

Recall that since the regulating reserves are procured to balance the second-to-second fluctuations in supply and demand, the generators must produce energy. When regulating reserves are being sold, the supplier earns two income streams: one for reserving the capacity and the other for energy produced. As was previously noted, the opportunity cost of not providing ancillary services spurs the decisions regarding the market any given generator wants to be in. The following formula represents the basis of opportunity cost calculations:

$$\pi_{Energy} = PP - (coal + STS) \tag{1}$$

$$\pi_{\mathrm{Re}\,gulating} = t * (PP - coal - STS) + Fee \tag{2}$$

$$Excess\pi_{\mathrm{Re}\,gulating} = Fee + (t - 1) * (PP - coal - STS) \tag{3}$$

where, coal denotes the marginal cost of supply; STS denotes fee paid for transmission use; and PP denotes the price in the energy market. (It should be noted that the TA procures regulating reserve as a range. Thus, if 20MW is being purchased that implies that the profits from producing 20MW of energy are being earned with some probability expressed as t, the ratio of dispatch volumes to the contracted volumes. Industry assumes that probability to be equal to 50%).

Example 4 : *Choosing Markets*

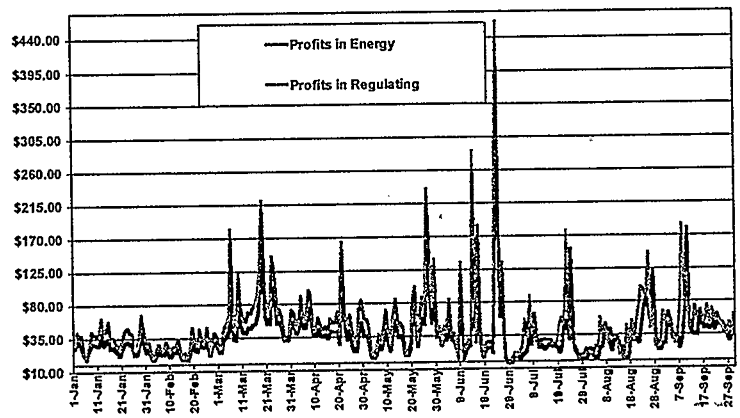
Recall that due to substitutability between energy and ancillary services, a generator participating in the market for capacity forgoes potential profits that it could earn in the energy market. By providing regulating reserves, the generator saves the costs of production but foregoes profits from supplying energy. Thus opportunity cost of providing regulating reserves is as follows:

$$X = +(coal + STS) - (PP - coal - STS)$$

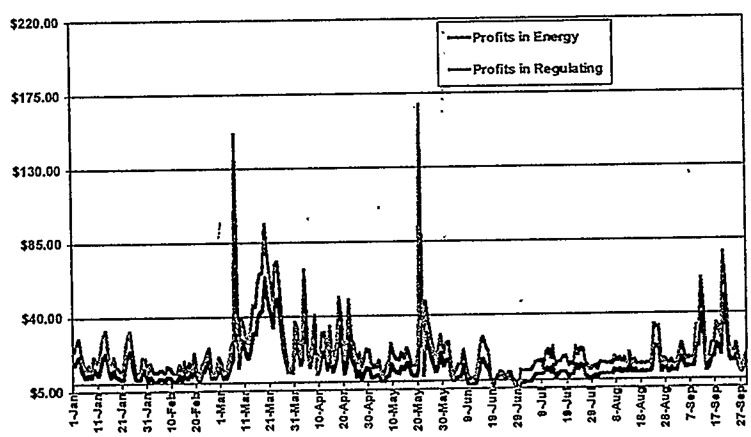
Assuming that $coal = \$3.50$, $STS = \$5.00$, $PP = \$60.00$, then $X = -\$43.00$. Thus, the generator could sell regulating reserves at $Fee = \$25.75$ and be indifferent to selling energy. Since the regulating reserves bids are indexed to PP, generator's bid would be $PP - 34.25$, where $34.25 = 60 - 25.75$

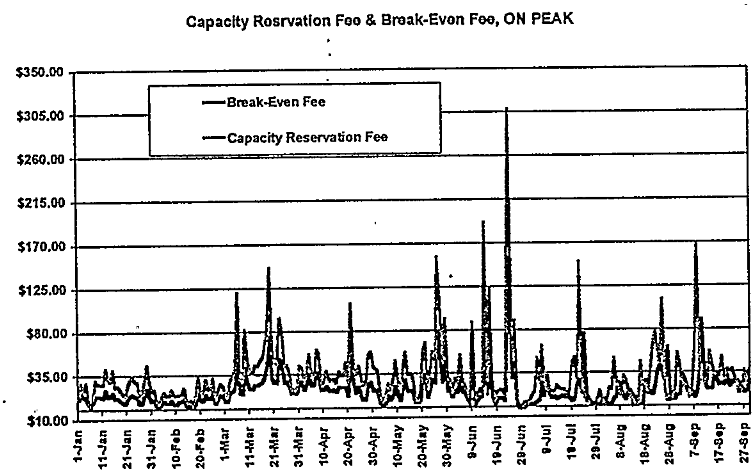
When the expected profits in two markets were graphed (using equations (1) and (2)), the expected profits in regulating markets exceeded expected profits in the energy market at all times during the nine month period. Referring to equation (2) it appears that the capacity fee generators receive causes the inflated earnings in the regulating reserves market. When the market fee and the break-even fee (the fee that would equate energy profits and regulating reserves profits) were graphed, the former exceeds the latter on average by \$15.00 per MWh. Thus, we can conclude that generators have a greater incentive to participate in the regulating reserves market rather than in the energy market under the current pricing scheme that overestimates the capacity fee charged by the generators.

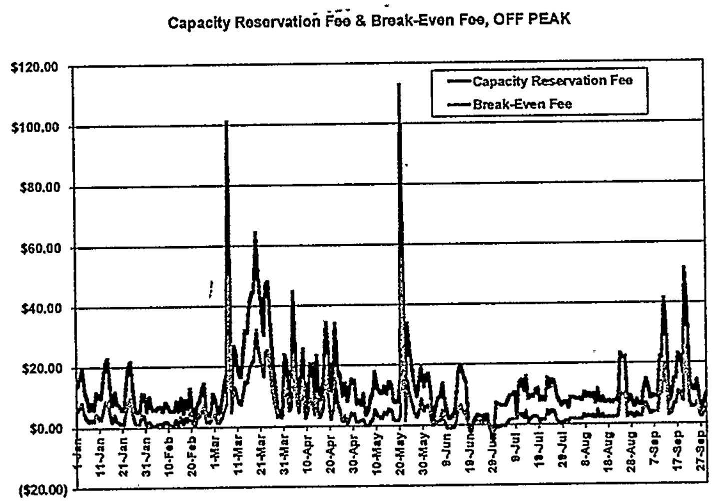
Energy Profits & Regulating Reserves Profits, ON PEAK



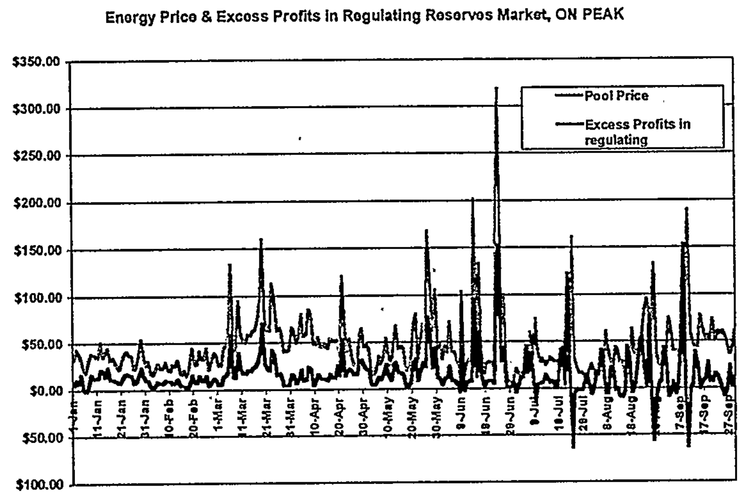
Energy Profits & Regulating Reserves Profits, OFF PEAK

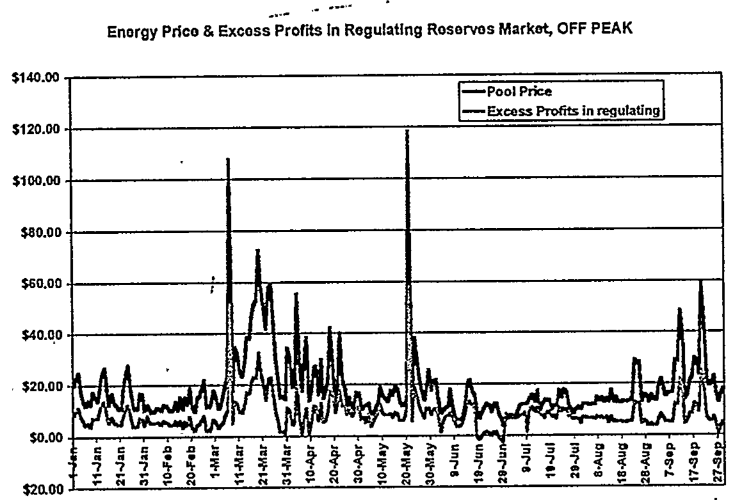






Recall that figures 12, 13, 14 and 15 graph the total expected profits in the two markets and also show the divergence between a break even fee and the actual fee, however they don't present a clear picture of the overall degree of competitiveness in two markets. Figure 16 and 17 (below) graphs the excess profits earned by the generators in the regulating reserves market. The figures indicate that under the current pricing mechanism generators were able to earn excess profits over the nine month period and that the trend does not disappear at the end of the sample period.





Econometric Analysis Before we can proceed with the empirical tests of market power in the regulating reserves market we need to examine the relationship between the energy price and the excess profits earned in the regulating reserves market. From the raw data, depicted in Figures 16 and 17, we can infer that as energy price increases so do the excess profits. This implies that market power in energy market results in the ability to exercise an even greater market power in the regulating reserves market.

I initially investigate whether energy price (PP) and the excess profits (EP) are non-stationary time series. The augmented Dicky-Fuller (ADF) unit root test was applied to those series. The ADF tests the null hypothesis of a unit root against the alternative of stationarity. The null hypothesis is rejected in favour of stationary alternative when the absolute value of the test statistic exceeds the critical values. Table 3 shows the results of ADF test for price and excess profits series.

	ON PEAK		OFF PEAK	
	PP	EP	PP	EP
ADF without a trend				
1%	−2.58	−3.98	−2.58	−2.58
5%	−1.95	−3.42	−1.95	−1.95
10%	−1.62	−3.13	−1.62	−1.62
Calculated t statistic	−1.55	−2.36	−1.62	−1.58
ADF with trend				
1%	−3.98	−2.58	−3.98	−3.98
5%	−3.42	−1.95	−3.42	−3.42
10%	−3.13	−1.62	−3.13	−3.13
Calculated t statistic	−2.05	−1.05	−2.74	−2.81

Since the calculated t statistic is below the ADF critical values for PP and EP in both periods, the null hypothesis of a unit root is not being rejected. Thus, I can conclude that both series are nonstationary.

Energy price (PP) and the excess profits (EP) are both non-stationary time series. If we regress PP on EP we would encounter a problem of spurious regression. The standard t and F testing procedures would no longer be valid. From Figures 1 and 2 we can infer that both series seem to be trending together for on-peak and off-peak conditions. Each series follows a random walk and those random walks seem to be in unison. Such an example of synchrony is intuitively the idea behind cointegrated time series. Despite the fact that both PP and EP are nonstationary stochastic processes, the linear combination of these two variables might be stationary. More specifically :

$$u_t = EP_t - \beta_1 - \beta_2 PP_t$$

If we find that u_t is I(0), then EP and PP are said to be cointegrated and the regression on the levels of the two variables is meaningful and we do not lose any valuable long-term information, which would result if we were to use their first differences instead. The null hypothesis of a unit root was rejected at all levels of statistical significance, thus we can conclude that EP and PP are cointegrated and that there seems to be a stable long-run relationship between them (using DF tests and RATS software). The next step is to regress PP on EP and find their correlation coefficient. When the ordinary least squares (OLS) method was used, we run into a problem of heteroskedasticity and autocorrelation. In order to avoid them we estimated the relationship employing the generalized least squares (GLS) technique. Using our data set we obtain the following results:

On Peak:

$$EP_t = 1.374 + 0.283 PP_t$$

$$t = 0.33,\ 3.08$$

$$R^2 = 0.51$$

$$\bar{R}^2 = 0.49$$

Thus for a \$1.00 rise in the energy price (PP) during the on-peak period, the excess profits (EP) increase by \$0.28.

Off Peak:

$$EP_t = 0.0975 + 0.432PP_t$$

$$t = 0.27, 23.83$$

$$R^2 = 0.80815$$

$$\bar{R}^2 = 0.8074$$

Thus a \$1.00 increase in the off-peak energy price causes the excess profits to go up by \$0.432.

Both of the above estimated equations suggest that excess profits are correlated with the energy prices, regardless of the period at hand. From equation (3) below we can infer that as the energy price goes up, the fee must increase in order for the excess profits to go up. The ability to increase the fee indicates that firms are able to exercise market power in the regulating reserves market in both on-peak and off-peak periods.

The correlation between PP and EP can be driven by Hydro withdrawal from the regulating reserves market whenever PP is high in the energy market. Although Hydro can provide energy at the lowest variable costs, the availability of its water is limited. Therefore, Hydro will postpone its participation in the energy market until its expected profits from selling energy will exceed its expected profits in the regulating reserves market. Since each firm participating in the Power Pool can forecast the demand and supply conditions of the AIES, Hydro will try to move into energy market and sell its output when prices spike. This implies that there is one generator less in the regulating reserves market and the remaining participants are able to raise their Fee.

The excess profits in the regulating reserves market are calculated using the following formula:

$$t * (PP - VC) + Fee - (PP - VC) \tag{3}$$

$$t = 1 - \frac{Fee}{(PP - VC)} \tag{4}$$

The data set does not allow me to calculate the actual t (does not include the dispatched volumes), thus the excess profits graphed above were estimated using the industry $t = 50\%$. This is a very strong assumption that may not reflect the true operations of the market and may also be the cause of high expected profits in the regulating reserves market. In order to examine the market power in the regulating reserves market, I am going to estimate at what level of t there would be no excess profits, given the actual energy prices and reservation fees. I am going to find the "benchmark" t by choosing t to make $\pi_R = \pi_E$. To test for market power I formulate the following hypothesis: if t is near 50% (the estimate of t commonly asserted in industry), then there is no market power in the regulating reserves market. The results from estimating t are reported in Table 4.

Month	Benchmark t	95% Confidence Interval
January	0.07	$0.01 < t < 0.14$
February	0.12	$0.08 < t < 0.17$
March	0.15	$0.11 < t < 0.19$
April	0.13	$0.06 < t < 0.20$
May	0.05	$-0.02 < t < 0.0$
June	0.26	$0.15 < t < 0.38$
July	0.49	$0.31 < t < 0.67$
August	0.46	$0.26 < t < 0.66$
September	0.38	$0.24 < t < 0.52$

The monthly averages show that for the months of January, February, March, April, May, June and September 2002 $5\% < t < 26\%$, thus the numbers confirm that there is excess market power in the regulating market. However, by the end of the sampling period (for July and August), t approaches 50%. When the average of the nine months was taken $t = 23.4\%$, thus the regulating reserves market appears to suggest excessively high reservation fees and hence the exercise of market power. Looking at the 95% confidence intervals we can conclude that only for the last three months out of 100 times 95 times we will obtain a value that includes industry $t = 50\%$.

If the industry $t = 50\%$ is assumed, then for $\pi_R = \pi_E$, the actual fee should have been equal to the calculated break-even fee, which is on average \$15 less than the actual fee. However, by observing real-time operations we can infer that the generators participating in the regulating market not only are called on 50% of the time but they are able to charge a higher reservation fee. Such a behavior is sustainable since there are only a few firms in the market facing relatively inelastic demand.

6.1.2 Interpretation of the Test Results

Current reliability criteria require that a minimum level of regulating reserves is maintained at all times in order to safeguard the security of the Alberta Control Area. The TA has estimated that the necessary amount of regulating reserves to balance the supply and demand within one hour is 120 MWs. This number constitutes a relatively small block of the overall capacity available. However, only generators with a small opportunity cost in energy market can provide it cheaply. The cost constraints allow us to conjecture that not many generators enter the regulating reserves market, although the benefits of participating are enormous. For one, the regulating reserves are being called on 50% of the time, thus the generators are receiving two streams of income, from reserving the capacity and from producing energy. If such high benefits accrue to the participating generators one might expect fierce competition within the regulating reserves market, reflected by a continuously lower capacity fee. However, from Figure 16 we can infer that excess profits are not being reduced to zero within the nine month period. Rather, the excess profits tend to rise when PP increases. This implies an even greater ability to exercise market power in the regulating reserves market. There are two possible explanations for this phenomenon. First, it could be that at times of high prices in the energy market, reserves are more likely to be called on, so that in that case firms competing in regulating reserves benefit not only from the "usual" activation but also higher energy market prices when actually activated.

A second possible explanation is that typically when prices get very high in the energy market, it is in part because of generator outages – if several plants are offline for maintenance or other reasons, this will tend to force prices up – but the effect of those outages is even more pronounced in the regulating reserves market.

The pattern of excess prices in the regulating reserves market is inconsistent with the first explanation. If the activation fee at times of high expected and actual energy prices remained the same, the effect of higher energy prices would be to *reduce* excess profits. However, the second explanation is consistent with the facts of the industry. An important feature of the regulating reserves market is that fewer firms can participate in that market than in the energy market, simply because of the technical requirements in regulating reserves. Thus, when even one plant which normally participates in this market is off-line, the market power of other firms increases considerably (and more than in the energy market).

The data are also consistent with implicit collusion by firms in the market, although this thesis advances no evidence for or against implicit collusion. In the normal market process, a rational competitive supplier bases its offer price on the expected market-clearing price,not on its own short-run marginal cost curve (SRMC curve). It then offers to sell at that price the amount that maximizes its profits. However, an electricity market with its dynamic and complex operations makes such a process unnecessarily costly and at times unreliable. Thus, the Pool of Alberta coordinates the market-clearing and pricing process and a competitive supplier submits a bid curve with different prices at different quantities, in effect creating a simple marginal cost curve that approximates its true SRMC curve. However, since the prices are being posted on the Pool's website and become a public information, market participants can monitor the prices other generators charge. For example, generator A has an incentive to raise prices by some percentage point. If generator B does not match the price increase, then A will be undercut and lose some of its profits. However, if A can quickly and costlessly observe the prices B charges, the risk of being undercut for significant period of time is small. If B doesn't match, then A can quickly rescind its price increase. Thus, it is in B's interest to match A, since the gains from not matching will be short-lived and small relative to the alternative of matching the price increase. Therefore, the price transparency rather than promoting competition, allows generators to closely monitor each other's strategies, to eliminate the price differences among the generators and to result in the overall increase in the average price of ancillary services (in particular the capacity reservation fee).

Brien (1999) argues that consistent pricing between markets for reserves and the energy is essential for the entire electricity market to work well. She further asserts that if the markets have no link with one another, with the energy market taking place first, the price of reserves may never equilibrate to the opportunity cost of forgone energy sales. In Alberta, there is no explicit division between the suppliers in energy and ancillary services markets. Generators can submit their bids for regulating reserves five days prior to dispatch, at the same time they can participate in the energy market. Since prices are publicly available, generators can estimate when the price in the energy market is going to spike up and incorporate that hike into their regulating reserves bids. As can be inferred form Figure 16 a price spike in the energy market is accompanied by a similar price increase in the regulating reserves market. The excess profits are a difference between the capacity fee and the energy profits. Thus, in a time of a price spike in the energy market, the excess profits in the regulating reserves market more than compensate for the foregone profits in the energy market.

Figure 16 shows excess profits in the regulating reserves market during the peak hours when demand is the highest and the need for the regulating reserves ever greater. In order to see the robustness of my analysis Figure 17 graphs the excess profits in the regulating reserves market during the off peak times. Again we can see that the excess profits are greater than zero at all times during the nine month period. Thus, not only do we observe weak competition during the peak hours but also during the times of lower demand.

7 Conclusions

The deregulation of the electricity industry was expected to bring large benefits to wholesale buyers and residential consumers. This expectation was based on evidence from other network industries that had undertaken market reforms. In the case of natural gas, a National Energy Board report (NEB, 1997,3) concluded the following:

> All Canadian gas consumers have benefited from increased choice and overall lower prices. In the decade since deregulation, Canadian gas buyers, on average, paid prices equal to or lower than the prices U.S. buyers as measured at the Alberta border. Along with increased choice of supplies and generally lower prices since deregulation, this provides strong evidence that the natural gas market is functioning in the best interest of Canadian gas buyers.

However, electricity has some features which make it different from natural gas and other network industries, a fact which is reflected in the performance of deregulated electricity markets world-wide. These markets are plagued by market design flaws which in many cases enhance the ability of market participants to exercise market power. In order to correct market design imperfections regulators have established institutions whose role is specifically to examine generator behaviour. However, most of the regulatory oversight focuses on the *energy* market and the bidding strategies of the generators participating in that market. It is vital that the regulatory bodies recognize that the system operator is running markets for energy *and ancillary services.* Failing to do so can result in unnecessarily high prices in the energy and ancillary services markets and can exacerbate system reliability problems. Ancillary services are an integral part of a well functioning electricity market. They allow the system operator to maintain the security of the electric system as well as cover the shortfalls in generation.

The goal of this thesis was to determine whether generators participating in the regulating reserve market have the ability to exercise market power, and it used data from the period January 1 to September 30, 2002 to test for such market power. From the same block of capacity a given generator can provide ancillary services or energy but not both at the same time. Due to this product substitutability the manner in which ancillary services are being procured affects the amount of available capacity and hence the prices in energy markets.

I began by calculating excess profits in the regulating reserves market and ascertained that they exceeded zero. This finding indicates that the regulating reserves market is not working competitively. Furthermore I utilized the operating reserves pricing model which provided some suggestion of market power. I looked at the relationship between the *Reservation Fee* and the *Pool Price* (*PP*) and have found that they are positively correlated. Thus an increase in *PP* results in a higher *Fee*. This in turn causes short run profits to go up allowing generators in the regulating reserves market to earn even greater profits over time. The final portion of my analysis calculates what probability of reserve units being called on to supply energy would be required to eliminate excess profits in the regulating reserves market. If reserve units were called on only around 23% of the time, the profitability in the reserve market would be about the same as in the energy market. However, industry participants claim that the actual rate at which reserve units are called on is around 50%, implying that there are substantial excess profits in the regulating reserves market. This finding further supports the claim that there is market power in the regulating reserves market. If the Alberta energy market is competitive, higher prices occurring in that market are a natural result of peak demand times. However once incorporated into the *Fee* structure of the regulating reserves they are transformed into the ability to exercise market power by the generators participating in the regulating reserves market. Thus in order to control the exercise of market power in the regulating reserves market we need a regulatory regime that will closely monitor the strategic behaviour of the generators, in particular the *Fee* that they charge.

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