University of Alberta

Determining the Effects on Residential Electricity Prices and Carbon Emissions of Electricity Market Restructuring in Alberta

by

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Abstract

When electricity restructuring initiatives were introduced in Alberta, and finalized with the institution of retail electricity market competition in 2001, it was argued that the changes would deliver lower electricity prices to residential consumers. However, residential electricity prices in Alberta increased dramatically in 2001, and have never returned to their pre-restructuring levels. Proponents of restructuring argue that electricity prices would have been even higher under continued regulation, citing the effect of considerably higher natural gas prices and the roles of other variables. However, many Alberta residential electricity consumers tend to attribute their higher electricity prices to factors such as market power and manipulation associated with restructuring.

Since the effects of restructuring on electricity prices cannot be evaluated by simply comparing prices before and after it occurred, the main objective of this thesis is to determine what electricity prices would have been under continued regulation, and to compare them with what was actually observed. To determine these counterfactual electricity prices, a structural model of the determinants of Alberta residential electricity prices is developed, estimated for the pre-restructuring period, and used to forecast (counterfactual) prices in the post-restructuring period. However, in forming these forecasts it is necessary to separately account for changes in explanatory variables that could be viewed as occurring due to the restructuring (endogenous) from those changes that would

have been likely to have occurred anyway. Information from US jurisdictions is used to account for this endogeneity issue through simulation analyses. Results suggest that for 2001 to 2004, residential electricity prices in Alberta would generally have been lower under continued regulation.

Since electricity market restructuring is not necessarily directed only at lowering the electricity price, its impact in Alberta on carbon emissions is also investigated. Specifically, the approach developed in the context of electricity prices is applied to determine counterfactual carbon emissions. While it is found that carbon emissions would have been lower under continued regulation, this result should be viewed cautiously given model estimation issues. However, the approach developed to construct both counterfactual electricity prices and carbon emissions is an improvement to that observed in the literature.

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Chapter 1: Introduction and Overview

1.1 Introduction

Electricity market restructuring has been undertaken to varying degrees in several Canadian provinces, most notably Alberta and Ontario. Other provinces, such as British Columbia and Quebec, have adopted structural or regulatory changes in order to adapt their systems to restructured markets in neighbouring U.S. states. When electricity restructuring initiatives were introduced in Alberta, it was argued – as in other jurisdictions where restructuring initiatives were promoted – that the changes would deliver lower electricity prices to residential consumers than would otherwise be the case.[1] In Alberta, the restructuring initiatives culminated with the establishment of retail electricity market competition in 2001. Although Alberta residential electricity prices were among the lowest in Canadian cities prior to this time, residential electricity prices in Alberta increased dramatically in 2001, immediately following the last stage of the restructuring. In the post-restructuring period in Alberta, residential electricity prices in Alberta have not been lower than their pre-restructuring levels, and indeed have never returned to their pre-2001 values. Although inflation has meant that prices have increased everywhere, Edmonton, when ranked on the basis of electricity prices alongside other Canadian cities, remains at a similar rank in 2010 as it had been at in 1998 (Hydro Quebec, 2010).

While these absolute and relative (across jurisdiction) price changes, or lack thereof, could be due to a variety of factors, they have frequently been attributed specifically to the effects of restructuring. Proponents of restructuring argue that electricity prices would have been even higher had restructuring not been pursued, citing the role of drastically higher natural gas prices and other variables. However, Alberta residential electricity consumers appear to remain unconvinced, tending to attribute their higher electricity prices to factors such as market power and manipulation associated with the restructured Alberta electricity market. Such attribution might indeed be justified, but it is not appropriate to simply compare prices before and after restructuring to determine the effects of such a significant change in market structure. This is because values of many other variables also changed during this period, and these changes

[1] Some years after restructuring, it is difficult to still obtain government documents – that were typically posted on their websites in the period leading up to restructuring and for a short time thereafter – that rationalize restructuring initiatives with the goal of lowering electricity prices. However, the following studies provide indirect references to the promises made by various governments of lowering electricity prices through restructuring initiatives. Klitgaard and Reddy (2000) state that deregulation failed to deliver the promise of lower electricity prices in the US, Wallace (2001) states that the Alberta government promised lower electricity prices through competition, while the Ontario Electricity Coalition indicates in the "Questions and Answers about Electricity Deregulation" section of their website (http://www.electricitycoalition.ca/q-and-a#question7) that Bill 35 was introduced in Ontario with the promise of lower electricity rates. Since all three sources refer to consumers, it seems that residential sector consumers are being referred to either solely or in conjunction with industrial and/or commercial consumers, although they are not explicitly singled out.

may, at least partially, account for the electricity price changes that were observed. Thus, while the focus of consumer interest might be on whether prices after restructuring are lower than the prices that they previously faced, we concentrate on comparing post-restructuring prices with what prices would likely have been in the absence of restructuring.

While the impact of electricity market restructuring can be studied based on characteristics such as its impact on the reliability of electricity service, choice to consumers, innovation in the electricity market, etc., this dissertation focuses specifically on the effects of restructuring on residential electricity prices. In particular, we attempt to determine what these residential electricity prices would likely have been in the post-restructuring period if restructuring had not occurred, and then compare these so called "counterfactual" prices to the actual prices observed in this period. If these counterfactual prices are higher than the observed prices, it would suggest that restructuring did help to keep prices lower than they would otherwise have been. However, if the counterfactual electricity prices are lower than the actual prices, this suggests that the effect of restructuring – in terms of electricity prices faced by consumers – was to make these prices higher. We believe that in view of other changes that may have occurred, this approach to evaluating the impact of restructuring on electricity prices via counterfactual price comparisons is more appropriate than a naïve approach of simply comparing electricity prices before and after restructuring and using that comparison to draw conclusions on the overall value of electricity market restructuring to residential consumers.

This dissertation focuses on investigating the impact of the electricity market restructuring that occurred in Alberta – beginning in the mid 1990s – on residential electricity prices, because the greatest objection to restructuring has stemmed from residential consumers rather than industrial consumers who might have expected to benefit from, and hence tended to largely support, such restructuring.[2] However, since restructuring of electricity markets is not necessarily – or at least not solely – directed at lowering the cost of providing

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[2] Under rate-or-return regulation, electricity prices are based on average costs. However, these are joint costs (across different sectors), and various formulas are used to share these common costs among the various sectors. It is possible that residential consumers benefitted from this pre-restructuring allocation of common costs, while the commercial and/or industrial sectors did not do as well. From this standpoint, the introduction of restructuring and the move towards marginal cost pricing might be expected to have a negative impact on residential (and possibly commercial) consumers, resulting in an electricity price increase, although such an outcome is not consistent with claims to the contrary made when restructuring was being introduced. It would nevertheless be interesting to also consider the effects of restructuring on prices in these other sectors, although such analysis is beyond the scope of this dissertation.

It should also be noted that focusing on a single sector – residential – provides only a partial view in terms of the overall benefits to society of electricity market restructuring. Even if such restructuring results in higher electricity prices for residential consumers due to marginal cost pricing, it may result in lower average cost due to higher efficiency, and higher profits to owners. Thus, there may be a net positive benefit for society as a whole.

electricity, this dissertation is also concerned with one other aspect of restructuring, namely an evaluation of the impact of the electricity market restructuring in Alberta on carbon emissions.

Just as in the context of electricity prices, the impact on carbon emissions is complex. On the one hand there is a view that by instituting competition, restructuring would contribute toward innovative ways of minimizing environmental damage from pollution and might therefore be expected to reduce carbon emissions from the power sector. On the other hand, it could be argued that by contributing toward incentives to produce electricity as cheaply as possible, and in view of Alberta's relatively abundant and inexpensive coal supplies, electricity market restructuring, could make it less likely that carbon emission reductions would occur with restructuring. Thus, in addition to evaluating the impact of electricity market restructuring on electricity prices, this dissertation also evaluates which of these two views concerning the impact of restructuring on carbon emissions appears to be more applicable to Alberta. As in the context of electricity prices, our focus is on determining what residential carbon emissions would likely have been in the post-restructuring period if restructuring had not occurred, and then comparing these so called "counterfactual" carbon emissions to the actual carbon emissions observed in this period. If these counterfactual carbon emissions are higher than the observed carbon emissions, it would suggest that restructuring did help to keep carbon emissions lower than they would otherwise have been. However, if the counterfactual carbon emissions are lower than the actual carbon emissions, this would indicate that the effect of restructuring – in terms of carbon emissions – was to make these carbon emissions higher.

This dissertation comprises three main components that are developed in Chapters 4, 5, and 6, with the first two of these three chapters relating to electricity prices while the third is concerned with carbon emissions. The methodology for constructing counterfactual values is initially developed in the context of electricity prices and then applied to the case of carbon emissions. As such, the third component could be viewed as an application of the framework developed in the first two components of this dissertation. The motivation for developing the first two components – to determine counterfactual electricity prices in the post-restructuring period and compare them with those actually observed – derives from the fact that although many studies have been conducted in various jurisdictions in different countries where electricity market restructuring has been implemented, for the most part these studies summarize and/or compare information on electricity prices before and after restructuring rather than analyzing the actual effects of the restructuring. In particular, studies for various countries that may focus on different aspects of restructuring often arrive at conflicting conclusions concerning the effects, and particularly the benefits, of restructuring.

The basic framework that is developed in Chapter 4 to obtain the counterfactual prices involves the formulation and subsequent estimation of a structural model of the determinants of electricity prices in the (regulated) period prior to restructuring. This estimated model is then used in conjunction with observed values of the relevant variables in the post-restructuring period to forecast electricity prices that would have been observed in the post-restructuring period in the absence of restructuring. These forecast prices, the so called counterfactual prices, are compared to the prices that were actually observed in the post-restructuring period. Systematic under-prediction of the actual electricity prices in this latter period would indicate that electricity prices increased as a result of restructuring, and the differences between the forecasted and actual values of electricity prices could be used to provide a quantitative measure of the extent of any such increase.

Of course a shortcoming of this approach is that restructuring itself may have caused changes in the values in the post-restructuring period of some of the explanatory variables that are used to model electricity prices. For example, restructuring may have increased the share of natural gas-based electricity generation by increasing the feasibility of employing natural gas-fired plants in the absence of regulatory approval delays that may have been inherent in the regulated system. Nevertheless, treating the observed values in this way serves two purposes. First, it can be used to provide a base case to which other specifications can be compared. In particular, it facilitates evaluations of the effects of various variables that might be expected to have evolved differently in the absence of restructuring. Second, the analysis with this base case can be used to determine if there is *prima facie* evidence that electricity prices increased as a result of restructuring.

As noted earlier, treating observed values of variables subsequent to restructuring as though they have been unaffected by electricity market restructuring, as in the first component of the analysis, may not be appropriate. Therefore, in evaluating the effects of restructuring it is necessary to separately account for changes in variables that could be viewed as occurring due to the restructuring from those that would have been likely to occur anyway. Analysis of this issue underlies the second component of the analysis in this dissertation. As developed in Chapter 5, this analysis includes an examination of other Canadian and US jurisdictions to determine if the values of the explanatory variables in Alberta in the post-restructuring period could be replaced with values from one of these other non-restructured jurisdictions. As an alternative, restructured and non-restructured US jurisdictions are compared to determine the likely effect of electricity industry restructuring on explanatory variables, with a view to modifying the observed values of these variables in Alberta in the post-restructuring period to adjust for these effects. After removing the potential impact of restructuring from the actual post-restructuring Alberta values of the explanatory variables, through a difference in differences approach, new sets of counter-factual electricity prices are constructed and compared with the prices that were actually observed in Alberta in the post-restructuring period. These new sets of counterfactual electricity prices are viewed as an improvement on the counterfactual electricity prices based on the naïve approach used in Chapter 4.

As mentioned earlier, the third main thesis component applies the methodology developed in the context of electricity prices to carbon emissions. Together, the analysis contained in these three components provides a picture of the effects of electricity restructuring in Alberta, particularly in terms of its effects on residential consumers through electricity prices, and its impact on carbon emissions. The analysis developed in the first two components adds to the literature that focuses on the impact of restructuring on electricity prices, specifically, in light of the fact that many studies pertaining to Alberta electricity prices are not concerned with estimating a structural model, but instead model the spot electricity price, that is, they focus at the wholesale level rather than at the retail level. Moreover, to the author's knowledge, the only other study that has determined counterfactual electricity prices in the context of the Alberta electricity market – Wellenius and Adamson (2003) – provides potentially misleading information in that their study does not recognize the issue of endogeneity that is addressed in the second component of this dissertation.

It has been observed in the literature that investigates the impact of restructuring on electricity prices that while studies conducted by the industry and consultants typically report price savings from restructuring, studies conducted by academics tend not find evidence linking lower electricity prices and electricity market restructuring. Even in more recent studies, contrasting results have been reported. Given these differing results found in the literature, it is important to try to take account of factors that may explain these differences, or that may at least help explain why industry studies tend to obtain results that are more favourable to restructuring. In this context, the methodology developed in this dissertation potentially makes a key contribution in terms of accounting for the important issue of endogeneity that has heretofore not been effectively addressed. The model developed in Chapter 4 is more comprehensive than many of the models used in the literature, and augmented by the novel simulation approach developed in Chapter 5, puts on a formal footing a framework that can be used to analyze restructuring, as well as providing empirical evidence about the effects on consumers of restructuring in Alberta. Likewise, the application of this methodology to carbon emissions is also quite novel, specifically given the observation that most economic studies that deal with carbon or GHG emissions tend to either be broad simulation-based studies or do so within macroeconomic frameworks that attempt to relate GHG emissions to GDP growth. Thus, this dissertation will contribute to the policy debate concerning electricity restructuring, particularly in Canada, but also in other jurisdictions that may perhaps be considering such a change.

1.2 Outline of the Dissertation

While the three main components of the dissertation that are developed in Chapters 4, 5, and 6 have been discussed in the previous section, here we provide a detailed outline of the entire dissertation.

Chapter 2 provides a description of the Alberta electricity market, delineates the factors that led toward restructuring initiatives in the province, and highlights the institutional changes that were brought about as a result of electricity market restructuring. The timeline for analysis of the Alberta electricity market spans from 1981 to the post restructuring period after 2001. The focus in this chapter is on the issues faced in the market prior to wholesale market restructuring in 1996, followed by the main factors that contributed to the subsequent power purchase agreements, and eventually retail market restructuring in 2001. Essentially, the purpose of Chapter 2 is to provide the context for restructuring initiatives in Alberta, and thus a general setting for the methodology that is developed in Chapters 4 and 5.

This methodology includes the development of a structural model of the determinants of electricity prices in Chapter 4, as well as simulation analysis in Chapter 5 to account for the endogeneity issue based on information derived from a review of electricity markets in 51 US jurisdictions. To this end, the objective of the literature review in Chapter 3 is not only to provide the motivation behind restructuring initiatives in various jurisdictions across the US, including the issues inherent in the traditional regulated framework, but also to help identify various variables that might be appropriate to consider in formulating the structural model of electricity prices that is developed in Chapter 4. Moreover, the literature review in Chapter 3 also provides an overview of results from various studies that have investigated the impact of restructuring on electricity prices, and also helps to identify model estimation issues. As such, Chapter 3 provides the context in which the model developed in Chapter 4 can be placed, and in which the simulation analysis developed in Chapter 5 can be shown to improve upon the existing body of studies that investigates the impact of restructuring on electricity prices.

Together, Chapters 4 and 5 comprise the two major components of this dissertation. Specifically, in Chapter 4 a structural model of the determinants of electricity prices is developed, and this model is subsequently estimated using data for the pre-restructuring period in Alberta. Various alternative specifications of the model are also considered. Using the estimated parameters from this model along with observed values of the explanatory variables in the post-restructuring period, forecast, or counterfactual, residential electricity prices for the post-restructuring period in Alberta are obtained. These counterfactual prices are then compared to actual prices observed in the post-restructuring period in order to assess the effects of restructuring on electricity prices. While this analysis does not take into account the endogeneity issue, namely that restructuring itself may have induced changes in the post-restructuring period values of some of the explanatory variables that are used to model electricity prices, it does provide *prima facie* evidence of the effect of restructuring on electricity prices. Moreover, it facilitates evaluations of the effects on electricity prices of changes in various variables that might be expected to have evolved differently in the absence of restructuring, and as such the model provides a base setting for the simulation analysis developed in Chapter 5.

The objective of Chapter 5 is to construct a method that can effectively address the issue of endogeneity. To this end, this chapter is heavily based on analysis undertaken on various Canadian and US jurisdictions. Specifically, restructured and non-restructured US jurisdictions are compared to determine the likely effect of electricity industry restructuring on selected explanatory variables, with a view to modifying the observed values of these variables in Alberta in the post-restructuring period to adjust for these effects. Based on effects determined through a difference in differences approach that uses this information, values of potentially endogenous explanatory variables in the structural model of the determinants of electricity prices in the post-restructuring period in Alberta are modified by replacing their observed values with a distribution of likely values in each post-restructuring year. Via a simulation method that involves random drawings from these distributions for these explanatory variables in order to obtain values to use with the estimated pre-restructuring period model in Chapter 4, new sets of counter-factual electricity prices are constructed and compared with prices that were actually observed in Alberta in the post-restructuring period. These new sets of counterfactual electricity prices are viewed as an improvement on those obtained with the naïve approach of Chapter 4, an approach that already represented an improvement over those that have previously appeared and been applied in various forms in the literature. On the basis of the methodology and conclusions in Chapters 4 and 5, a critical appraisal of Wellenius and Adamson (2003), the only study to have determined counterfactual electricity prices in Alberta, is undertaken (Appendix 5.2). It is shown how, among other factors, failure to account for endogeneity could result in a misleading analysis.

In Chapter 6, which constitutes the third main component of this dissertation, the methodology developed in Chapters 4 and 5 in the context of electricity prices is applied to carbon emissions. As such, this chapter provides another metric, that is, carbon emissions, to evaluate the impact of electricity market restructuring in Alberta. The basic framework of Chapter 6, similar to those developed in Chapters 4 and 5, involves the construction of a model for carbon emissions and, subsequently, after accounting for endogeneity, obtaining a set of counterfactual carbon emission values, that is, the values of carbon emissions assuming continued regulation in the post-restructuring period. While Chapter 6 essentially involves an application of the Chapter 4 and 5 methodologies, it also adds to the literature, particularly in view of the observation that most previous economic studies that deal with carbon or GHG emissions tend to either be broad simulation-based studies, or utilize macroeconomic frameworks that attempt to relate GHG emissions to GDP growth.

Finally, Chapter 7 contains a summary and conclusion based on the results and analysis of Chapters 4, 5 and 6. It indicates how the methodology developed in Chapters 4, through a comprehensive rather than a selective model, and Chapter 5, by accounting for endogeneity, improves upon the existing approaches used in the literature. Chapter 7 also very briefly touches upon the issue of alternative models of restructuring and re-regulation. As is suggested in Chapter 7, a comprehensive review of these options could be an interesting subject for future research.

Chapter 2: Background – The Electricity Industry in Alberta

2.1 History in North America

At the beginning of the 20th century, electricity generation was in the hands of private investors both in Canada and the US (Parkinson, 2003), although many businesses (non-utilities) generated their own electricity. Intense competition between electric power providers and subsequent downward pressure on prices gave rise to concerns that investors would be reluctant to make additional capital investments (EIA, 1997b: 1). It has been observed that in some industries with economies of scale, competition may persist for a while, but only until bankruptcies and mergers erode it (Phillips, 1993), and in the early 1900s, this is what happened to the electricity sector in the US.

As some electricity-generating utilities failed and/or were purchased by others, the industry became more concentrated. High construction and maintenance costs led to the notion of a natural monopoly in the electricity sector. Operational and investment complementarity between generation and transmission activities eventually led to the integration of the two segments of the industry (Trebilcock and Hrab, 2004:3). Economies of scale were achieved through capacity additions, and technological advances that resulted in declining costs. Thus, increased convenience and more economical services provided by larger and more efficient generators of electricity (utilities) induced a shift to utilities for electricity demand requirements.

Later, these largely unregulated utilities began to exercise market power through higher prices, and this helped support a move in the U.S. toward regulation and government-owned power companies (EIA, 2000a: 5-6). In return for being allowed to operate as a monopolist within a specified region (usually a state), utilities were typically subject to a number of regulations that included rate regulation as well as a prohibition on providing electricity to other regions. However, in the late 1960s the situation started to change.

The northeast blackout of 1965, the Clean Act Air of 1970, the oil embargo of 1973-74, regulatory delays, and inflation, which led to a tripling of interest rates (thereby raising capital costs), were all contributing factors toward restructuring in the US (EIA, 2000a: 8). The previously declining average costs and stable prices were adversely impacted by energy supply disruptions and high capital costs. The traditional views on regulation of a monopolistic electricity industry were challenged in the 1970s when it was observed that many large generation plants exceeded sizes consistent with minimum average cost (Burtraw et al., 2000: 6).

Technological developments of the 1980s, specifically the introduction of combined cycle gas turbine plants that reach minimum average cost at smaller output levels (thereby lowering the cost of capital), also contributed to changes in attitudes toward restructuring (Burtraw et al., 2000: 3). In the mid-1980s it was realized that public ownership and regulation had resulted in costly generation technologies and that scale economies in generation had been exhausted at a unit size of about 500 MW (Savolainen, 2002: 13, 26). Given these changes in capital costs and technological developments, restructuring became more feasible because now competition could be effectively induced as more utilities could enter the market employing cheap capital to construct smaller generators. Thus, all of these changes in capital costs and technological developments were factors leading toward restructuring in the US and possibly in Canada.

However, despite all these changes, restructuring has progressed at a slower pace in Canada than in the US because of Canada's large endowment of hydro power in many provinces,[1] the low cost coal deposits in many Canadian jurisdictions, and the low cost of capital resulting from provincial securitization and exemption from federal income tax. As far as Alberta is specifically concerned, while it has (very) limited hydro-based power capacity, cheap supplies of coal would seem to reduce the motivation to restructure in much the same way as in jurisdictions like British Columbia, Manitoba, Quebec and Newfoundland that predominantly generate hydro-based power (Jaccard, 2002: 19, 20).

2.2 Alberta Timeline

In order to provide a framework for subsequent analysis, it is convenient to use a timeline to organize events that occurred in the Alberta electricity industry. One timeline that captures the key events is as follows:[2]

- 1981: Energy Price Pooling begins in Alberta
- Early 1990s: Commissioning of new power plants causes industry tension
- 1995: First restructuring legislation is passed.
    - 1996: Wholesale competition is introduced
    - 1998: Limited retail competition is introduced
- 2000: First auction of power is conducted
    - 2001: Retail competition begins
    - 2002: Second auction is conducted
    - 2003: The first restructuring legislation is amended

The following subsections consider these four main event categories in greater detail. The main focus of this examination is to identify the forces that caused the industry to take the form that it did, to determine the factors that led to

[1] For hydropower, average costs are lower than marginal costs of production (EIA, 1997b, 57). It may be recalled that prices under regulation are based on average costs whereas competitive prices are based on marginal costs, which would explain the slower pace of restructuring for jurisdictions with hydropower.

[2] Kennedy (2003) presents a timeline that deals only with the restructuring process.

restructuring, to examine the specific form of restructuring that occurred, and to investigate the factors that were affected by restructuring or by restructuring expectations. This last part, concerning factors that were affected by restructuring, deserves special attention specifically in the context of Chapters 4 and 5 of this dissertation. In these chapters we develop a model to explain electricity prices in the pre-restructuring period that we then use to forecast counterfactual prices that would have been observed in the post-restructuring period had restructuring not occurred. This is done be using the estimated values of the parameters of the regression model from the pre-restructuring period in conjunction with observed values of the explanatory variables in the post-restructuring period. However, values of some of these explanatory variables in the post-restructuring period may have been affected by restructuring – an issue dealt with in Chapter 5 – so that it is necessary to determine the effects of restructuring on variables like capacity in order to make appropriate adjustments to the method used to generate the counterfactual prices. While, the relevant explanatory variables for the models developed in Chapter 4 and 5 will be identified through the literature review in Chapter 3, this section is geared toward generally identifying the forces that led toward restructuring of the electricity market in Alberta.

2.2.1 Electric Energy Marketing Act: EEMA

Over time, and especially since the early 1960s, most electric generation utilities in Canada came to be publicly owned, with vertical integration of the three main components: generation, transmission and distribution (Mapleleafweb, 2001; Byfield, 2001).[3] The situation in Alberta differed somewhat, in that two of its three large generation utilities – Alberta Power (subsequently ATCO), and TransAlta Utilities[4] – were investor owned as opposed to being public entities. The other large generation utility, Edmonton Power (subsequently EPCOR), was and currently remains an Edmonton municipal body, although in 2009 its generation facilities were spun off to Capital Power Corporation (CPC), of which EPCOR remained a majority owner.[5] The other unique aspect of the Alberta electricity market is its relatively isolated nature as compared to other Canadian and most US jurisdictions. While the Alberta grid is connected with British Columbia to the West and Saskatchewan to the East, even by the end of 1995 these two lines provided only about 550 MW of electricity, which represented about 6% of Alberta's generation capacity (Daniel et al. 2006).

[3] In the US, privately-owned utilities were the dominant form of organization, in terms of output and capital. US DOE (2007) indicates that the private investor-owned utilities represented 38% of installed capacity, 42% of generation and 66% of sales. In contrast, publicly-owned electricity utilities represented 9% of generating capability, 8% of generation and 15% of retail sales.
[4] Although TransAlta was investor-owned, the electricity distribution system for the city of Calgary, which TransAlta supplied, was municipally owned.
[5] See EPCOR's history, available at http://www.epcor.ca/en-ca/about-epcor/corporate-overview/Pages/History.aspx, which references the creation of CPC in July 2009.

Of these three utilities, TransAlta was the biggest player comprising 50% of the generation capacity, whereas each of the other two comprised approximately 20% of generation capacity.[6] By 1995, these three vertically integrated utilities accounted for 90% of the total capacity of 8600 MW.[7] At this time, within Alberta, electricity generation was fueled primarily by coal (66%), followed by natural gas (23%) and hydro (10%).[8] The three major players were franchise monopolies regulated by the Alberta Energy Utilities Board (AEUB) under a cost of service framework. (Daniel et al., 2006) In other words, each acted as a monopoly in its own regionally designated area. This meant that the utilities were allowed to recoup their investment and operating costs and earn a return determined by the AEUB.

In 1982, owing to a widening difference in generation and transmission costs between franchise areas, the Alberta government enacted the Electric Energy Marketing Act (EEMA) to ensure uniform wholesale electricity rates. Under EEMA, a provincial agency bought electricity from generators at cost of service (COS) rates and sold it to retailers at an averaged uniform rate (Jaccard, 2002: 19-20). Utilities were required to charge a price that averaged the cost of generation and transmission, and hence the same price was set across the province (Alberta Energy Savings L.P., 2005). However, this price-smoothing raised a number of other problems.

Prior to EEMA, electricity was cheaper in southern Alberta, which was supplied by TransAlta, so that this equalization of prices meant that wealth was transferred from southern to northern Alberta (which was served by ATCO and EPCOR) (Mapleleafweb, 2001) as equalization of prices effectively subsidized the rates paid by consumers in northern Alberta. TransAlta and the other utilities[9] strongly objected to this equalization process because it was negatively impacting their overall operating revenues (Alberta Energy Savings L.P., 2005). Because of this price-smoothing across regions, EEMA differed from COS regulation. Consumers and businesses in southern Alberta faced increased costs. Moreover, others argued that since distribution costs were omitted from the EEMA equalization formula, widely dispersed rural consumers faced higher costs compared to locally concentrated consumers served by municipal utilities (AESO,

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[6] Daniel et al (2006), p. 4, the numbers refer to the early 1990s, though the authors have not provided a specific date.

[7] The 8,600 MW figure is taken from Daniel et al (2006). There are two sources of generation data, Electric Power Statistics (EPS), in which capacity is subdivided into hydro, internal combustion, and gas turbine subcategories, and Alberta Electric Industry Annual Statistics (AEI), where capacity is subdivided by fuel type, such as coal, natural gas, etc. For 1995, EPS identifies capacity as 8312 MW, while AEI specifies 8590 MW, which corresponds to Daniel et al, assuming that their value is for 1995.

[8] Around this time, heavily subsidized wind generation of electricity began to enter the grid, but even today wind provides only a relatively small proportion of Alberta's electricity requirements.

[9] The authors do not indicate whether by utilities they mean ATCO and EPCOR or other smaller utilities based in the south, though it seems logical that operating revenues would be reduced for the latter as opposed to the former.

2006). Thus, it appears that TransAlta and consumers in southern Alberta stood to benefit from restructuring that would do away with the EEMA terms.

Even in the absence of EEMA, the COS regulation itself may have prompted utilities to push for restructuring. Regulation that assures the utilities a rate of return on their costs of providing service (COS framework) possibly encourages them to expand, despite the risk of regulators disallowing some costs, in order to increase their share of an expanding electricity market. This behavior – the Averch-Johnson effect[10] – was compounded in Alberta by the EEMA framework, as utilities could build new capacity (although this had to be approved by the regulator) at the expense of the *provincial* rate base, so that costs were recouped from all Alberta electricity consumers rather than just customers of the particular utility undertaking the investment (Howard and Lurie, 2000). Another possible explanation for this expansion under the COS framework is that even in this pre-restructuring period, firms were trying to position themselves in anticipation of a time when they would be allowed to supply electricity throughout the province. It is not surprising therefore that TransAlta spearheaded an aggressive campaign in favour of deregulation, since in anticipation of larger market share low cost utilities are usually set to benefit from industry restructuring (Byfield, 2001).

2.2.2 G1, G2 Commissioning

Apart from the price equalization issue created by EEMA, another motivation for restructuring stemmed from the construction of new plants such as Genessee (by EPCOR), and Sheerness (jointly by ATCO and TransAlta). The construction of these plants was pursued despite the oil price decreases of the 1980s, which put a brake on the Alberta economy and hence on the demand for electricity (Byfield, 2001). While the utilities continued these investments, possibly in a bid to obtain greater market shares, consumers ended up paying the higher costs due to the COS framework that was in place. Thus, not only did TransAlta have an incentive to support restructuring, now consumers had a motivation as well.

However, there were also a number of other factors that provided motivation for restructuring. According to Daniel et al. (2006), the reasons for the drive toward restructuring included the belief that allowing for private decision-making in the market would increase efficiency compared to decisions based on regulation. Other reasons included the need to control the high costs of regulation, as utilities were investing substantial amounts of time in regulatory hearings in order to obtain approval for capacity expansions or price increases. Moreover, given regulatory constraints, utilities had little incentive to invest in

[10] Named after the study by Averch and Johnson (1962) that first identified this effect. Specifically, as explained by Zajac (1970), the Averch Johnson effect refers to rate-of-return regulated utilities having higher capital-labour ratios at their profit-maximizing output level than the ratios that would minimize cost for the chosen output level.

newer technologies, due to the risk that should new technologies fail to work utilities would not be able to recoup their costs especially if these costs were not allowed to enter the rate base. It is to be noted that under the COS regulation framework, profits are governed by the rate of return so that there is not as much incentive for profit maximization as returns beyond the regulated rate would be siphoned away under the pricing system established by the terms of regulation.

It also appears that given the global and industrial trend toward restructuring, Alberta did not want to lag behind, and wanted to retain its low cost power advantage (Alberta Resource Development, 1999). Thus, the need or desire to retain the low cost advantage propelled the restructuring process further. The global trend was clear: downsizing, privatization, outsourcing, globalization, reducing government involvement in the electricity sector (Mapleleafweb, 2001) following the successful restructuring in industries like airlines and telecommunications, and early restructuring of electricity industries in the UK, Australia, and announcements of restructuring in several Asian countries like Thailand, Indonesia and South Korea in the aftermath of the East Asian crisis.[11]

Technological advances also meant that smaller natural gas generators could be constructed at low cost and in a fraction of time taken to build the larger coal-based generators. This fact, coupled with the desire of large industrial consumers to take advantage of low-cost natural gas plants, also helped to propel the movement toward restructuring. Despite the fact that the cost of new natural gas-fired generation is higher than the embedded cost of older coal-fired units (Case and Akman, 2001), since there were regulatory issues that hampered the addition of new coal based generators, as it could take up to 14 years to get a new generation plant online (Alberta Energy, 2004), the balance was tipped in favour of restructuring. In moving from regulation to competition, the preference appears to have been for low fixed cost / high operating cost natural gas plants that are quickly built, as opposed to high fixed cost / low operating cost coal plants that take a longer time to be built. This suggests that capital costs may be a more important consideration than operating costs.

The relative importance of capital costs becomes apparent when it is noted that in Alberta, coal prices (in dollars per gigajoule) have generally been lower than natural gas prices. (This is discussed in more detail in Chapter 4). Of course this needs to be tempered by differences in the average heat rates of plants, defined as the amount of GJ required to produce one GWh of electricity, which in Alberta from 1965-2006 has been higher for coal (11,250 GJ/GWh) than for natural gas (7,280 GJ/GWh). Regardless, while the low capital costs of natural gas-based generators may explain the shift toward them, a question that arises is whether this shift would have occurred without restructuring.

There also existed an interesting viewpoint held by some that since natural gas prices might be expected to rise as natural gas reserves decline, coal would

[11] See, for example, Asia Pacific Energy Research Centre (2000).

become relatively cheap (Haggett, 2001).[12] Of course, from an environmental viewpoint, greenhouse gas emissions associated with burning coal to produce electricity are much higher than when natural gas is used,[13] and even though technology may have helped to mitigate the emissions produced from coal-based electricity generation,[14] the expectation of stricter environmental standards in the future may also have contributed to this shift towards natural gas-based generation. An additional factor that may have contributed toward this shift is the peak demand problem – the fact that natural gas-based generators can be ramped up very quickly to produce electricity, whereas the process is much slower for coal-based plants.[15] With possible anticipation of higher peak period pricing, the ability to produce for this peak market – facilitated by natural gas-based generation – may also have been an important factor. Despite all these considerations, an unanswered question that arises is whether the trend toward natural gas-based generation is likely to be reversed at some time if relative fuel costs change significantly, and whether from a long-run viewpoint it may have made more sense to invest in coal-based generation, particularly in the context of Alberta where coal-based capacity has not increased since 1994, and where capacity growth since 1998 has been predominantly based on generators fueled by natural gas.

In the environment that existed in this era, including the aforementioned incentives towards restructuring, and in particular the low capital cost of natural gas-based generators, new investment in the early 1990s was actually curtailed due to deregulation uncertainty (Case and Akman, 2001). It is clearly prudent to avoid heavy capital investment if one is not sure of the conditions under which the expenses are to be recouped (Mapleleafweb, 2001). This uncertainty about the future added to capital costs through higher borrowing costs as investors demanded higher risk premiums. There are additional reasons why policy uncertainty and technological change may have impeded new investment. Policy uncertainty would imply the need to build plants in such a way so as to account for more stringent environmental standards, perhaps due to the Kyoto Protocol (Globe and Mail, June 6, 2002). Also, according to the real options argument,[16] technological change might induce utilities to wait for better technologies to become available in the market.

[12] Of course, this view pre-dated developments in exploiting shale gas deposits, so it may no longer apply.

[13] In fact, compared to natural gas, coal is twice as emission-intensive due to its heavy carbon content per unit of energy released (Quadrelli and Peterson, 2007).

[14] See for instance, Beer, J.M., (2009) "Higher Efficiency Power Generation Reduces Emissions", National Coal Council Issue Paper 2009, MIT Energy Initiative, http://web.mit.edu/mitei/docs/reports/beer-emissions.pdf (Accessed July 7, 2011)

[15] See, for example, Soto (2009).

[16] See, for instance, Botterud and Korpas (2004), who indicate, in the context of their mathematical model, the optimal strategy is either to invest immediately or postpone the investment.

This stands somewhat in contrast to the earlier noted additions of the Genessee and Sheerness plants in the early 1990s out of the desire for capacity additions, although these plants did have a long gestation period. Moreover, Wellenius and Adamson (W&A) (2003) indicate the reverse situation may have applied: in anticipation of restructuring investors actually started showing interest in building new generating plants. This issue has implications for whether or not restructuring led to decreased investment in generation capacity. If it did, then this effect would need to be controlled for in the subsequent analysis considered in Chapter 5.

2.2.3 Electric Utilities Act (EUA) [Initial Stages of Restructuring]

The Electric Utilities Act was enacted in 1995 and implemented on January 1, 1996, primarily to deal with generation restructuring in order to make decisions contingent on market forces, thereby leading toward increased efficiency. Under this Act, control of utilities' transmission facilities was transferred to an independent transmission administrator to ensure non-discriminatory access to the transmission grid. The Electric Utilities Act also created the Alberta Power Pool (Pool) that was to facilitate market-based trading of electric energy.

With this Act, the government legislated fixed price contracts between the generation and distribution divisions of the utilities regardless of the Pool price, that is, the spot price. These contracts, known as legislated hedges, required incumbent generators – those built before 1996 – to sell their power at variable cost in exchange for payments covering their fixed costs. While the fixed price contracts were designed to allow domestic consumers access to stable low retail prices, the Pool prices provided signals for supply investment decisions (Jaccard, 2002: 19-20). More specifically, the generation price between Jan 1996 and Dec 2000 was tied to the cost of service of regulated units so as to mitigate any exercise of market power by the three utilities and to protect retail customers and regulated generation units from the Pool price. Moreover, under the legislation, residential and farm consumers would not face restructured retail prices until July 1, 2006 (Trebilcock and Hrab, 2004:55). Since the legislated hedges effectively impeded market forces from setting the market price, an unfortunate side effect was that large capital investments may have been deterred due to uncertainties about the conditions under which the expenses were to be recouped (Mapleleafweb, 2001). In effect, the implementation of legislated hedges through the Electric Utilities Act dealt with the issue of market power at the expense of activating market forces.

Both existing regulated units and retail demand were insulated from the vagaries of the market, but new supply and demand were not. The system that would ultimately come into existence was the result of the 1998 amendment to the EUA, according to which the Power Purchase Agreement was formally recognized and the distribution segment of the industry was also restructured.

The EUA was crucial in that it was anticipated that the resulting competition would lead to downward pressures on price. However, growth in peak demand outstripped capacity and policy uncertainty froze capacity expansion plans, thereby leading to wholesale price hikes by November 2000. Policy uncertainty prevailed not only prior to the restructuring process but also continued well through the process. Apart from uncertainty, other factors contributing to the wholesale price hike include a generator plant that failed from August 2000 – May 2001, high electricity prices that prevailed in California, thereby diverting the usual power flow from BC to Alberta to California instead, and natural gas prices that were high in 2000-2001.

Thus, it appears that plant failure, exports, and natural gas prices explain most of the fluctuations in electricity prices (Daniel et al., 2006). If this is the case, and if after controlling for the effect of uncertainty, which presumably stems partly as a consequence of restructuring, one finds that prices were still quite high, then one could possibly conclude that prices would have risen anyway, with or without restructuring. Specific analysis that controls for the impact of restructuring on variables such as capacity is developed in Chapter 5.

2.2.4 Power Purchasing Arrangement (PPA) Auctions [Costs/Benefits of Restructuring]

While the EUA was the legislation that was used to initiate market restructuring, it is only after the introduction of the PPA auctions that restructuring in the real sense of the word was implemented. The main rationale behind these auctions was the avoidance of forced divestiture, as had happened elsewhere with restructuring. In the Albertan context, bidders were encouraged to take part in the auction to bid for the right to purchase electricity-selling rights from the generation utilities.

However, Jaccard (2002) indicates that the Alberta government forced utilities to divest themselves of production rights on generation assets through auctions of power purchase agreements (PPAs). Whether the divestitures were forced or not, these agreements required the successful bidder to purchase a fixed amount of output from an individual generating station for 20 years at a price equal to the marginal cost of generation plus a fixed monthly payment determined by regulators (Trebilcock and Hrab, 2004:53). Moreover, in an effort to limit market power, individual PPA holders were constrained to a maximum of 20% of the Alberta market for a 20 year period (Down et al., 2003b:3).

Notwithstanding the constraints on PPA holders, since only five buyers successfully applied for power in the original auction, it is not obvious that the auction process did in fact facilitate competition. According to analysts at Mapleleafweb, electricity generation was reduced and prices skyrocketed from 5 to 25 cents/kWh between June and October 2000 (Parkinson, 2003). Apart from the small number of entrants to the generation market, contraction of credit has been another factor that has impeded the construction of new generation capacity (Globe and Mail, April 9, 2004). Moreover, in the first auction, which was held in August 2000, 60% of the offered capacity was bought for $1.1 billion by the five large buyers. This auction, together with a second auction in December 2000 yielded a total of $2.2 billion in stranded benefits,[17] which were returned to consumers as rebates in 2001. Wallace (2001) noted that it had been argued that a successful auction outcome required at least $3 billion, which led to criticism of the large block size of the initial PPAs that effectively precluded smaller companies from participating in the auctions.

So far, the focus has been on issues concerning supply constraints. However, there is also the issue of increasing demand in Alberta. With consumers generally protected from the accompanying price increases through various rebates and credits, in Alberta as well as in a number of other jurisdictions, there was relatively little incentive for consumers to conserve electricity.[18] One may note though that demand was rising even before restructuring, specifically between 1993 and 2000, because of economic growth (Daniel et al, 2006). Therefore, the impact of customer shielding through rebates post-restructuring may simply echo the pre-restructuring trends in demand.

While generally prices in the post-restructuring period, particularly immediately after restructuring, were reported to have skyrocketed given the constrained supply and unchecked demand, some studies argue that this was just a temporary feature. For instance W&A (2003) indicate that the significant investment seen in Alberta since 2000 will continue to exert downward pressure on prices and that new capacity has been the primary driver behind falling wholesale prices. Trebilcock and Hrab (2004) note that approximately 2500 MW of new generation capacity was added to the Alberta system between 1998 and 2002 and that in anticipation of full retail restructuring, approximately 5200 MW of new generation capacity was expected to be added to Alberta between 2003 and 2006.[19] W&A (2003) also indicate that since restructuring has produced benefits like improved generation efficiency owing to the higher efficiency of

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[17] Stranded benefits arise when the market value exceeds the book value of generation plants.

[18] Pape-Salmon et al. (2001) indicate that due to high electricity prices, that is, wholesale electricity prices being five times as high in 2001 than three years earlier, the Alberta government offered rebates to both consumers and businesses in 2001. Pohlmann and Kelly (2001) mention both rebates and credits being offered to small and medium sized business in Alberta in 2001.

[19] The extent to which this new generation capacity materialized is somewhat unclear. The website for Alberta Energy (http://www.energy.alberta.ca/Electricity/682.asp) indicates that since 1998 over 6,400 MW of generation capacity has been added, but according to the Statistics Canada publication, *Electric Power Generation, Transmission and Distribution*, (http://dsp-psd.pwgsc.gc.ca/Collection-R/Statcan/57-202-XIB/57-202-XIB-e.html), which “presents data on supply and disposition of electricity in Canada from utilities and industrial establishments which generate and/or distribute electric energy”, accessed series from 2004-2007 indicate that the increase in generation capacity in Alberta from both public and private utilities between 2003 and 2006 was only 767 MW.

new natural gas-fired generators, Pool prices did not increase at the same rate as natural gas prices.

Case and Akman (2001) mention that, given the increase in power pool prices in late 2000, the Alberta government froze the retail electricity rates at $0.11 / kWh and decided to provide a subsidy of $40/ month to protect consumers from the high electricity retail price that would have prevailed. However, they also indicate that since the frozen retail rate[20] was close to the market price (for 2001 the Alberta Pool price was $0.132/KWh, while the frozen price level was $0.11/ KWh[21]), customers were making decisions based on prices that were closer to the relevant spot prices. This stands in stark contrast to the observation noted earlier that since consumers were shielded by rebates, demand decisions were not market-based. This study also indicates that although market uncertainty leads to reduced generation capacity and higher prices, as a consequence those higher prices would induce investment in generation, thereby helping to eventually curb prices. However, a critique of this analysis could be that the timeline for higher prices fuelling investment could be quite long, and also this argument does not take into consideration the impact of credit constraints.

2.3 Preliminary Evaluation of Restructuring

Restructuring that is accompanied by supply shortages exacerbates volatility, limits competition and induces the exercise of market power. In Alberta, the market faced supply shortages when it opened in 2001 (Down et al., 2003a). Moreover, it seems that despite the capacity investments indicated by W&A (2003) and Trebilcock and Hrab (2004), and despite divestitures through the two PPA auctions, market power was in fact exercised. Trebilcock and Hrab (2004) cite a report by the Alberta Market Surveillance Administrator (AMSA) that claims that in the summer of 2000, electricity was being sold at prices higher than marginal costs of production, and that generators might have kept generation capacity offline without a valid physical or operational justification. It has also been argued that Alberta electricity prices increased because exports and imports were permitted to set the market-clearing price, that is, BC was importing electricity from Alberta to re-export to California (Trebilcock and Hrab, 2004:54).

Recapping, the issues associated with restructuring in Alberta can be attributed principally to an exercise of market power arising from few sellers and transmission congestion, strategic bidding due to poor market design, lack of consumer response to price spikes because of rate freezes, capacity shortage due to relatively high demand not met by new capacity, impediments to new capacity

[20] Jaccard (2002) refers to fixed price contracts between generators and distributors, whereas Case and Akman (2001) refer to the retail price freeze. It seems that Jaccard loosely employs the fixed price contracts in the context of average retail prices, whereas it would be more appropriate to distinguish between frozen retail prices (between distributors and consumers) and fixed prices between generators and distributors.

[21] Trebilcock and Hrab (2004) indicate that while the regulated rate was capped at 8 cents/kWh in November 2000, it was raised to 11 cents/kWh in 2001.

resulting from regulatory uncertainty, and inelastic demand which magnifies the price effects of capacity shortage and market power (Woo, Lloyd, and Tishler, 2003: 1103, 1109).

Our overview indicates a number of major issues that arose in the Alberta restructuring context and which no doubt shaped the outcome of the restructuring process. Perhaps the main issue was the divestiture that led to very few PPA holders and which led to a situation where market power was exercised.[22] While we do not consider this issue explicitly in our subsequent analysis, it might be expected to have affected the prices that consumers faced for electricity, and these prices, and the effect that restructuring had on them, is the focus of Chapters 4 and 5.

Some of the studies considered here in this review of the development of the electricity industry in Alberta go beyond merely describing the changes in the industry to speculating about the effects that restructuring may have had. These often contradictory analyses seem to raise a number of issues about the structure of any model that might be used to examine electricity prices in the Alberta environment. Since Chapter 4 develops a model that is used to evaluate the effects of restructuring on electricity prices faced by consumers in Alberta, in Chapter 3 a more comprehensive review of the literature is provided.

[22] However, in markets such as Pennsylvania such divestiture was not required, which provides yet another contrasting viewpoint in the Alberta electricity market restructuring context.

Chapter 3: Review of the Literature

3.1 Introduction

Electricity market restructuring can be studied based on such aspects as its impact on improving the reliability of electricity service, providing an array of choice to consumers, enhancing innovation in the electricity market, and bringing forth cost savings (Robbins, 2003). However, this dissertation focuses specifically on the cost savings to consumers that result, at least in theory, from the institution of competition through restructuring efforts. The success of restructuring in instituting competition can be gauged through indicators like the number of electricity providers, or the percentage of consumers who shifted to alternate providers (Kapur, 2004), whereas the cost savings resulting from competition can be gauged from computations based on electricity prices. This thesis focuses predominately on the electricity price as opposed to the other criteria for measuring restructuring "success".

Many studies have been conducted in various jurisdictions in different countries where electricity market restructuring has been implemented, although often these summarize observations before and after the restructuring rather than analyze the actual effects of the restructuring, as is the focus of this dissertation. A review of all such studies is therefore not particularly useful. In particular, different studies for different countries that often focus on different aspects of the restructuring often yield conflicting conclusions. An example of this is provided by two studies, one that focuses on Australia and New Zealand and the other that studies the England and Wales electricity market. Improved plant utilization, better reliability, lower costs and electricity prices were observed in the post-restructuring period in Victoria, Australia, while electricity prices fell by about 20% between 1992 and 2000 in New Zealand (Dewees, 2001). However, higher labor productivity, lower fuel costs and increased generator efficiency did not lead to lower electricity prices after restructuring in England and Wales (Newberry and Pollitt, 1997).

In the context of the US, a review of the literature by Taber et al. (2005) finds that restructured utilities may have lower fuel costs (Markiewicz et al., 2004), lower non-fuel costs (Bushnell and Wolfram, 2005), may use less costly pollution permits (Fowlie, 2005) and may refrain from building non-profitable peak generation units (Mount, 2005). However, Taber et al (2005) qualify these findings by noting that market concentration, poorly designed markets, climate conditions and high fuel costs may have led to increasing electricity prices. The respective importance of market power and production costs can be gauged on a preliminary basis by noting that in California, 21% of the wholesale electricity expenditure increase from $2.04 billion in summer 1999 to $8.98 billion in summer 2000 was due to higher production costs and about 59% was due to market manipulation (Borenstein et al, 2002).

Clearly, a comprehensive review of the literature would require addressing the methodologies of the different studies in order to attempt to resolve the different results that are obtained. While such a review may underscore a number of different issues such as, for example, market power, this comes at the expense of losing focus on the structural model of the determinants of electricity prices, which lies at the core of this dissertation. Therefore, the review in this chapter focuses on the studies analyzed by Kwoka (2006), because the model developed here has similarities to the approach used in several of those studies. However, before examining these studies specifically, which is done in Section 3.3, and considering how the present analysis fits in with these previous studies, a brief summary of the history of and motivation for electricity market restructuring efforts, particularly in the US, is presented. This discussion includes both issues that have been identified with cost of service (COS) or rate of return (ROR) based regulation, as well as additional motivation and rationale for restructuring. In Section 3.4, results obtained from various other studies are discussed, including those highlighted in Blumsack et al (2008), while Section 3.5 considers models that have been estimated in the context of Alberta. A number of estimation or implementation issues that have been identified in several previous studies are discussed in Section 3.6, while Section 3.7 provides a brief summary.

3.2 History and Motivation for Electricity Market Restructuring[1]

There are a variety of reasons why electricity market restructuring has been undertaken in various jurisdictions including the US, the UK, Australia and New Zealand, and in two provinces in Canada. Where electricity restructuring included privatization of electricity utilities, it is likely that the motivation behind the move included reducing government involvement in the sector to reduce government debt. However, especially in the context of US jurisdictions that pursued electricity market restructuring, one principal motivation that is frequently noted was the desire to reduce electricity prices which were viewed as being higher for these jurisdictions under the cost of service based regulated framework for a host of reasons that included the Averch-Johnson effect, that is, over-investment by utilities that functioned within a regulated framework. Specifically, there were considered to be a number of problems inherent in the cost of service (COS) or rate of return (ROR) based regulation framework, as outlined below predominately in the US context, which instigated the move toward restructuring efforts.

3.2.1 Issues with COS or ROR regulation

While restructuring is often blamed for higher electricity prices due to reasons that include market manipulation and the exercise of market power by restructured utilities, Sutherland (2003) notes that there existed several problems

[1] The effects of the introduction of regulation on electricity prices as the industry in its infancy moved in the other direction – from being unregulated to being regulated – have previously been examined. See, for example, Stigler and Friedland (1962).

under the COS or ROR regulation framework. According to Sutherland (2003), under regulation, high inflation and interest rates penalized generator construction in the US in the 1960s, whereas rising fuel prices increased the costs of electricity generation during the 1970s. According to Fagan (2006), the high oil prices of the 1970s led to the Public Utility Regulatory Policies Act (PURPA) that required public utilities to establish long term contracts to purchase power from renewable fuel based generators. However, when energy prices declined in the 1980s and 1990s, the established contracts turned out to be costly, and these higher costs were passed on to consumers by the regulated utilities (Fagan, 2006). Apart from the costly long term contracts, due to overestimates of demand, numerous large scale costly plants were built in the 1970s and 1980s, which under the regulatory framework led to and compounded any price increases (US General Accounting Office (GAO), 2002). Other issues under regulation included coordination failures that, for instance, led to blackouts in the Northeast in 1965 (US General Accounting Office GAO, 2002).

Sutherland (2003) also applies the seminal work on regulation by Stigler (1971) to the electricity market, stating that the initial motivation for regulation stemmed from the desire of the electricity utility industry to limit and protect itself from competition. As such, Sutherland (2003) notes that low electricity prices under regulation are due more to low or subsidized fuel costs than to any inherent quality of the regulation itself. On the other hand, by stating that, under ROR regulation, utilities purchased fuel under long term fixed price contracts and in turn sold electricity at stable flat price rates, Sutherland (2003) seemingly tempers his critique of this ROR regulation framework (from a consumer's point of view), although this may not have been his intention.

Sutherland's (2003) attribution of low electricity prices under regulation to subsidized fuel costs is paralleled in the study by Lave, Apt, and Blumsack (2007a), who indicate that, under regulation, utilities were encouraged to increase investment in order to prevent events like the 1965 blackout, by providing them funds at preferential rates, that is, at rates less than the allowed rate of return. Likewise, Van Doren (1998) states that public utilities receive loan guarantees, exemption from various taxes, and various subsidies that include access to below market rates for financing.

According to Carlton and Perloff (2000), under a ROR regulation framework, the regulator allows the utilities a set rate of return, which provides them with an incentive to overinvest in capital in pursuit of a higher level of profit. ROR regulation therefore provides disincentives to minimize costs by using an optimal input bundle of labor and capital. Additionally, according to Sutherland (2003), ROR regulation provides little incentive for utilities to innovate and therefore reduce costs simply because, under such a framework, utilities can recoup their costs and earn a rate of return on prudent capital investments regardless of their economic value.

Not only does ROR regulation provide incentives to overinvest in capital, it actually provides disincentives to reduce costs because a utility that reduced its operating costs simply had its revenue requirement (the amount it was allowed to collect from rate payers) reduced (Lesser, 2007). Apart from providing disincentives to reduce costs, ROR regulation also provides disincentives to invest in new technologies as utilities could not recoup costs of investment in new technologies if they failed to work (Lave, Apt, and Blumsack, 2007a). Moreover, not only did regulated utilities have weak incentives to minimize capital, operating and labour costs, these costs were actually passed on to rate payers, as in the case of the introduction of unnecessary nuclear plants that increased electricity prices for consumers (Lave, Apt, and Blumsack, 2007a).[2] In fact, despite noting earlier that regulated utilities had access to subsidized fuel costs, preferential borrowing rates, and various tax exemptions, Lesser (2007) notes that in the early 1990s, under regulation, electricity prices were high even though fuel costs were low.

However, Carlton and Perloff (2000) also indicate that, while ROR regulation in general provides disincentives to minimize costs, the presence of regulatory lags does provide incentives to regulated utilities to minimize costs because in the short run, regulated utilities, by reducing costs, can earn profits until the next regulatory hearing when prices are lowered to reflect their lower costs. This incentive to minimize costs in the presence of regulatory lags becomes stronger if electricity demand exceeds its forecasted value and if input costs turn out to be less than expected, simply because, under these two situations, utilities would make profits based on the prior approved rates (Philipson and Willis, 2006).

In addition to these issues that various authors have identified as arising under regulation, namely that fuel prices may be subsidized, utilities do not minimize costs, they have disincentives to invest in new technologies, and they support regulation to protect themselves from competition, another issue that arises concerns the existence of inefficient electricity pricing simply because electricity prices are based on average rather than marginal costs. Specifically, Sutherland (2003) states that during base load periods, since the regulated flat rate exceeds marginal costs, capital (and therefore electricity) is overpriced, whereas during peak demand periods, since marginal costs exceed the regulated flat rate, capital (and therefore electricity) is under-priced.

[2] Specifically, Fagan (2006) cites a study by Smeloff and Asmus (1997) that indicates that the cost of failed investment in nuclear plants in Washington was around $13 billion and was generally born by consumers.

3.2.2 Motivation and rationale for restructuring[3]

As discussed above, there are many drawbacks inherent in a COS or ROR regulated framework, including unnecessarily high costs due to over investment that are passed on to consumers in the form of higher prices, the existence of high electricity prices despite low fuel prices, disincentives toward cost minimization and toward investing in new technologies, and inefficient electricity pricing that is not based on marginal costs. Notwithstanding these critiques and the point made by Sutherland (2003) that the electricity industry actually supported regulation to limit competition, the ROR regulation framework did have its merits as well. Despite their critique of such a framework failing to result in cost minimization, Lave et al. (2007a) identify ROR regulation achievements as including an increase in reliability and a reduction in electricity prices. Moreover, historically, the ROR regulation was required to encourage building of high-cost capacity, as without guaranteed returns, and therefore a reduction in the risks of investment, no private investor would have had the incentive to invest in electricity infrastructure (Philipson and Willis, 2006).

However, this latter justification for regulation is weakened somewhat subsequent to the construction of the requisite generation, transmission and distribution infrastructure, as any additional investment in any of these three areas does not have the same risks as the construction of the initial infrastructure (Philipson and Willis, 2006). Thus, in the aftermath of the construction of the initial infrastructure, regulation was no longer deemed necessary given technological advancements in smaller capacity natural gas plants, which could be built in a fraction of the time taken to build the larger capacity coal-based plants. In fact, regulation was beginning to be deemed more of a liability, as Lave et al. (2007a) indicates that State Public Utility Commissions would often take years to make decisions. This longer time frame for the decision-making process is understandable, as under ROR regulation, investment decisions were based on the evaluation of thirty years of projected benefits of coal- or nuclear-based generator plants. However, given the new technology of natural gas-based plants, investment would be considered only if the payback was less than five years, and this provided one justification for a competitive as opposed to the regulatory market framework (Philipson and Willis, 2006).

The regulatory framework that provided disincentives to invest in new technology, and the high costs due to overinvestment in nuclear-based generator plants and costly long-term power purchase contracts, both of which led to higher prices for consumers, led industrial consumers to support electricity market restructuring in order to harness technological advances that promised lower

[3] Two studies that framed the economic debate that led to the deregulation of the electric power industry in the US are Joskow and Schmalensee (1983), who showed that the economies of scale argument could not be used anymore to justify the regulation of private monopolies in the electricity industry, and Schweppe et al. (1988), who showed how competitive electricity markets could operate in the real world.

prices. The paradox of having over-capacity in generation and low natural gas prices but having high electricity prices was quite clear in California (Brown, 2001), which initially justified the move toward restructuring in that jurisdiction. Apart from California, several jurisdictions that had higher than average US average electricity prices stood to gain from technological developments that reduced the minimum efficient scale of generation, as well as technological advances in high voltage transmission lines that favored regional markets in contrast to local markets (Griffin and Puller, 2005). With these developments, jurisdictions with higher electricity prices could potentially have access to electricity at cheaper rates from other jurisdictions (Van Doren and Taylor, 2004). Both these developments – in smaller scale generators and in transmission lines – contributed to the onset of restructuring, as the former required the absence of lengthy and costly public utility commission hearings, while the latter required non-discriminatory access to the transmission grid.

According to Brown (2001), there were a variety of problems inherent in the regulation framework that all contributed toward restructuring. These included low wholesale electricity prices but high retail electricity prices due to long-term contracts between utilities and independent power producers that were set in the 1980s with the expectation of rising energy prices, the newly revised expectation of low natural gas prices and the simultaneous influx of new co-generation natural gas-based technology, the potential threats by some industrial customers to generate their own electricity, and above all the very framework of average cost based pricing that included the cost of older more expensive plants, built in the 1970s and 1980s due to overestimates of demand, in the estimation of the average costs that led to high electricity prices.

The motivation to reduce high electricity prices has been a principal theme noted in the literature as a justification for restructuring, as have some of the other issues associated with regulation highlighted above. Fagan (2005) notes that one motivation behind restructuring, to curb the high costs due to over investment in nuclear based generator plants, has been identified by Hogan (2001), Joskow (2000) and Borenstein and Bushnell (2000). Fagan (2006), Lave, Apt and Blumsack (2007a), and Griffin and Puller (2005) all note the shifting of risk in investment decisions from consumers to shareholders as an impetus for restructuring. This shifting of risk from ratepayers to shareholders is deemed to be important in terms of achieving the previously mentioned objective of curbing the overinvestment inherent in a regulatory framework.

Restructuring was pursued not only in light of the issues present in the regulation framework, and to lower electricity prices, as highlighted above, but also in order to obtain other benefits such as to provide consumers with retail choice and to increase innovation (Lave, Apt, and Blumsack, 2007a). A US General Accounting Office GAO (2002) study also notes lower prices, a wider array of retail services, improved efficiency in electricity generation, and innovation in retail electricity services as some of the benefits associated with competition brought forth by restructuring. However, in contrast, Borenstein and Bushnell (2000) note that electricity prices were expected to decline even in the absence of restructuring. For example, in California, high cost contracts made under PURPA were scheduled to expire and sunk cost payments for nuclear plants were paid off. It may be noted, however, that even if electricity prices would have decreased after the expiry of long-term contracts and the end of the payments for overinvestment in nuclear plants, the very issue of the Averch-Johnson effect, that is, of over-investment in general, would still not have been addressed had regulation continued, although, it could be argued that some alternative form of regulation – as opposed to restructuring in its present form – could have been considered.

Consideration of alternative forms of regulation, in contrast to focusing just on achieving restructuring, was perhaps not given more emphasis in view of the benefits that were observed to have been obtained through restructuring in other markets. As Blumsack and Lave (2005) note, substantial price reductions have been documented in deregulated industries including airlines, trucking, railroads and natural gas. Moreover, according to Sutherland (2003), if some jurisdictions pursued restructuring and others did not, there was a risk of being left behind in achieving any potential benefits of competition brought about by restructuring. Both restructuring in other industries and the risk of being left behind seem to have contributed to the instigation of restructuring efforts.

Motivations for restructuring in countries outside the US shared some similarities with those for the US jurisdictions. In the context of the European Union, Serralles (2006) mentions that under regulation, system stability and reliability as well as perceptions of stable and low electricity costs were obtained at the expense of economic inefficiency. These economic inefficiencies included oversized generation capacities and weak incentives for technological innovation. Serralles (2006) also mentions that it was the development of more efficient generation technologies, like the combined cycle gas turbine, that was one of the factors responsible for challenging the natural monopoly model in the electricity industry. While restructuring efforts in the European Union were somewhat motivated by issues reflected in the regulatory framework that were to an extent similar to those in the US, other countries undertook reform in the electricity market for other reasons.

Singh (2006) notes that while electricity market restructuring was undertaken in developed countries to harness the benefits of competition, the motivation for electricity market reform in India was to attract private investment to the power sector as it was unable to meet increasing electricity demand. Reform in the Indian electricity market included the functional separation of the generation sector from the transmission and distribution sector, which has also been one of the initial steps undertaken toward electricity market restructuring in developed countries. According to Asano (2006), in Japan, deregulation was motivated by high electricity prices in the 1990s. As such, competitive bidding for new generation capacity was introduced in 1996 and retail competition for large consumers was introduced in 2000. Similar to the situation in India, Taiwan experienced increasing electricity demand which the electricity market was unable to meet. This led to a power crisis during the summer peak demand months in 1999, which motivated the deregulation efforts in Taiwan (Wang, 2006).

Factors that motivated deregulation in Thailand were similar to those in India, Japan and Taiwan, as well as in the US and the EU. In Thailand, privatization and deregulation of the electricity market was in part pursued to meet growing electricity demand, a factor common to India, Japan and Taiwan, but also to reduce the liability burden on the public utility sector and to improve economic efficiency, which was one of the motivating factors for restructuring in the US (Chirarattananon and Nirukkanaporn, 2006). As far as Singapore is concerned, the principal motivation behind deregulation has been the lower electricity costs that have been associated with efficiency gains brought by competition – as perceived from restructuring efforts in the US, Australia and New Zealand – in order to retain the competitive advantage of its Foreign Direct Investment FDI reliant economy relative to India and China (Chang and Tay, 2006). Just as Singapore has motivated deregulation on the basis of the perceived benefits of restructuring in other countries, one motivation for restructuring the electricity market in the US has been the positive experience with deregulation in other industries. Fagan (2006) references works such as Crandall and Ellig (1997) and Morrison and Winston (1999), which indicate that consumers have saved billions of dollars due to deregulation of the airline and telephone industries.

To summarize, it appears that outside the US, where restructuring was pursued to obtain the perceived efficiency gains that were attributed to competition, in the East Asian economies of India, Japan, Taiwan and Thailand, the motivation for deregulation predominantly comprised a desire to alleviate the burden on the public sector in order to meet growing electricity demand. It also seems from the studies reviewed in this section, and on the basis of the previous chapter that addressed restructuring in Alberta, that motivation for restructuring efforts in Alberta comprised both types of rationales, that is, the fostering of competition as well as a desire to curb the inefficiencies inherent in the COS or ROR regulation framework. While the motivation for restructuring in Alberta appears broadly consistent with those identified for other jurisdictions, the efficacy of restructuring in lowering retail electricity prices, one of the objectives sought through restructuring, is a different issue. For that purpose, it is useful to focus on the various studies reviewed by Kwoka (2006).

3.3 Studies Reviewed by Kwoka (2006)

Kwoka (2006) documents that out of the twelve studies conducted in the US that he identifies, nine indicate that electricity market restructuring has led to retail price benefits or cost efficiencies. However, only four of these twelve studies are based on econometric models of the electricity price in which counterfactual electricity prices are determined and compared with actual post-restructuring electricity prices to determine the impact of restructuring on electricity prices. These four studies include Fagan (2005), Taber, Chapman and Mount (2005), Joskow (2006) and CERA (2005). The approaches taken in these papers are described below in order to compare and contrast them with the model developed in this dissertation.

Fagan (2005) determines counterfactual electricity prices for 2001–03 for US states based on a model where real industrial electricity prices for 1990–1997 are modeled as a function of real gas prices and a time trend. Fagan (2005) concludes that actual prices were lower than the counterfactual prices in the 2001-03 period for industrial customers in restructured states as compared to the non-restructured states, leading to the conclusion that restructuring has led to lower electricity prices. However, Fagan does not entirely attribute the lower post restructuring electricity prices to restructuring, noting that during the 2001–03 transition period, electricity rates were being set by a mix of competitive market and regulatory forces, as restructuring was not yet fully implemented.

Fagan (2005) also develops a model of the change in actual electricity prices, in contrast to the earlier model with levels of electricity prices, and concludes that neither retail market restructuring as captured by a dummy variable nor wholesale market restructuring as denoted by membership in a regional transmission organization are significant determinants of lower electricity prices in restructured states. While the models for both the electricity price levels and electricity price changes appear quite simplistic, Fagan (2006) develops a richer model of electricity prices as a function of nuclear share, the share of independent power producers, transmission capacity and power imports/exports ratio, and concludes that higher electricity prices are more likely to result in states with higher nuclear and independent power producer shares in generation. However, many details about this model, the time period, etc., are not expressly stated.

Taber et al. (2005) model both nominal and real retail electricity prices for four consumer classes (residential, commercial, industrial, overall) for three types of utilities (private in regulated states, private in restructured states, public utilities) leading to 24 possible model specifications for the 1990–2002 time period. Electricity prices are modelled as a function of variables that capture fuel costs, climate, share of generation from different energy sources as well as policy variables that include dummy variables reflecting whether a state has an auction-based wholesale market for at least one year. In contrast to Fagan (2005), Taber et al. clearly define restructuring at the wholesale level rather than at the retail level. Sensitivity analysis of the model includes using generation mix ratios instead of generation amounts, weighted fuel prices – defined as the product of generation share for each fuel type and fuel prices – instead of fuel prices, and the total generation figure to capture scale effects as opposed to generation mix effects. Taber et al. (2005) find that restructured states tend to use more natural gas and nuclear power and less coal and hydropower.[4] The results of the regression analysis do not provide any evidence for restructuring leading to lower electricity prices.

Joskow (2006) models the electricity price (average real retail residential or industrial price) for 1970–2003 as a function of the average real fossil fuel price, real yield on electricity utility debt, share of hydro based generation, share of nuclear based generation, average electricity consumption, and three policy variables that represent the share of generation from cogeneration sanctioned by PURPA, share of generation from wholesale generators beginning in 1998 to capture the effect of wholesale competition, and a dummy variable indicating the existence of retail competition. Joskow concludes that both wholesale and retail competition have led to lower retail electricity prices.

Cambridge Energy Research Associates *CERA* (2005) model electricity prices as a function of the fuel price and the rate base. More specifically, the CPI for electricity prices is modelled as a function of the real average cost of fuel for power generation and an index of the real return on capital. Like Joskow (2006), CERA use 1997 as the year that demarcates the pre- and post-restructuring time periods. The year 1997 is simply viewed as a cut off point for when the electricity market moved from regulation to having significant competitive mechanisms. Based on a model estimated from 1990–97, counterfactual electricity prices are obtained for the 1998–2004 period and it is concluded that restructuring gains totalled about $34 billion for this period.

3.3.1 Placing the Model in the Literature

These four econometric studies were reviewed because the model developed in this dissertation, while different in many details, falls neatly within the general approach taken by these four papers, that is, determination of counterfactual electricity prices through regression analysis. The differences between the model here and the four models described above are as follows. First, the four studies focus on many US jurisdictions whereas the analysis here focuses exclusively on one jurisdiction - the Alberta electricity market. This is important to note because issues like sample selection bias and treating the electricity price to account for stranded costs become non-issues here, which

[4] Of course, the greater use (and cost) of nuclear power (and low availability of coal and hydropower) may be a cause for the restructuring that occurred, while the increased use of natural gas may be a result of the restructuring. This issue is considered in more detail in Chapter 5, Section 5.5.

accounts for at least two of the critiques leveled by Kwoka (2006) at the four studies.

Second, the model here is quite comprehensive in that it was built not only to mimic the cost of service model but to also incorporate variables that have been highlighted in the literature as having affected the electricity price in the specific context of electricity market restructuring. Thus, the model developed in this dissertation attempts to account for many variables that have been selectively used in the four studies, namely capacity variables, heat rates, generation variables, capacity constraint variables, fuel prices, weighted fuel prices, demand variables and the cost of capital.

In contrast, Fagan (2005) merely focuses on natural gas prices and a time trend whereas CERA (2005) incorporates only the cost of capital and the cost of fuel. While the other two studies control for more factors – Taber et al (2005) account for fuel prices, generation mix and climate, whereas Joskow (2006) incorporates the fuel price, cost of capital, generation mix and a demand variable – none of the four studies account for capacity variables and heat rates.[5] It is important to include these two variables to control for capacity constraints and technological change.

Third, and most importantly, the model and analysis here goes beyond the conventional modeling for counterfactual prices, by using simulation analysis to account for the potential impact of restructuring on several of the explanatory variables (in Chapter 5).

Apart from Taber et al (2005), the other three studies conclude that electricity market restructuring has lowered electricity prices. While both Joskow (2006) and CERA (2005) make an unqualified claim, Fagan (2005) concludes that the finding of lower electricity prices after restructuring needs to be interpreted cautiously. These three studies that have employed an econometric framework are among the nine studies in the US context that conclude that restructuring has led to lower electricity prices. Outside of the seminal review by Kwoka (2006), studies conducted by the US government and by consultants, or studies in the specific context of the PJM market also provide a favorable view of electricity market restructuring.[6]

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[5] While Joskow (1997) states that some of the variation in electricity prices across states can be explained by average utilization rates, Joskow (2006) does not include capacity utilization rates in the construction of the counterfactual prices.

[6] PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, http://pjm.com/about-pjm/who-we-are.aspx (last accessed: August, 2011).

3.4 Results from Other Studies

According to the US Department of Energy, in states where wholesale competition has been introduced, consumers are saving $13 billion per year (Wood, 2005). Likewise, Global Energy Decisions estimate savings to customers in the Eastern Interconnection at more than 15 billion dollars (Taber et al., 2005). In terms of a specific jurisdiction, Taber et al (2005) report that Biewald et al. (2004) find that deregulated electricity prices in PJM are lower than predicted electricity prices under regulation. Sutherland (2003) notes that the states nearby the PJM market that did not restructure their electricity markets have not experienced a comparable electricity price decline as observed in the PJM market, which is hailed as the most successful case for restructuring initiatives. In fact, according to a survey in Maryland, 73% of residential electricity consumers believe competition leads to lower electricity prices (Zingale, 2008).

While studies by the government and some consultants point to the merits of restructuring, specifically in the context of the PJM market, other studies suggest that restructuring has led to higher electricity prices. Apt (2005) finds that restructured states as a group saw a 1.4% average annual retail industrial electricity price increase, compared with a 1.0% increase for non-restructured states. Likewise, Zingale (2008) cites a *USA Today* report that states that from 2002–2006, average electricity prices increased 21% in regulated states, but 36% in restructured states during the same period after the expiration of rate caps. In fact, Showalter (2008) states that even similar electricity price increases in restructured and non-restructured jurisdictions cannot be deemed equivalent; for instance, the 10 to 16 c/kWh (60%) electricity price increase in Connecticut – a restructured state – is not equivalent to the 4.1 to 6.4 c/kWh (56%) electricity price increase in Washington – a state that did not restructure its electricity market.

Different results on the merits of restructuring continue in more recent papers. On the one hand, Carlson and Loomis (2008), focusing on one specific jurisdiction, conclude that Illinois consumers have benefited from restructuring based on counterfactual electricity price changes determined by controlling for fuel price changes and capacity expansions. On the other hand, Showalter (2008), focusing on various US jurisdictions, concludes that electricity prices have increased in restructured states based on the counterfactual electricity price trend in restructured states determined on the basis of the trends in the electricity prices in non-restructured states.

Blumsack et al (2008) indicate that most studies have concluded that restructuring has led to efficiency gains, although studies report conflicting evidence on whether restructuring leads subsequently to lower retail electricity prices. Blumsack et al (2008) attribute the conflicting evidence reported in the literature to issues in the definition of restructuring as highlighted by Kwoka (2006), the failure to account for price caps (mandated upper limits for electricity prices), and the use of aggregated data. Addressing the Kwoka (2006) critiques predominately by using detailed firm level data, they conclude that restructured utilities display significantly higher price-cost markups in comparison to regulated utilities in the US. However, Kleit (2011) cautions on construing the Blumsack et al (2008) finding of higher price cost mark ups for restructured utilities as an indication of higher electricity prices, as the higher markups could also be explained by declining marginal costs.

Blumsack et al (2008) also discuss a wide array of literature that examines the impact of restructuring on both efficiency gains as well as electricity prices, two of the targets of restructuring efforts. They reference studies by Christensen and Greene (1976), Klitgaard and Reddy (2000) and Kleit and Terrell (2001), to indicate that efficiency gains from 3% to 13% have been experienced as a result of restructuring the electricity market. Blumsack et al (2008) indicate that, since capital costs comprise a greater portion of total costs, efficiency gains in the short term were to be expected from using generation capacity more intensively, which indicates an increase in the capacity utilization ratios in the short term. They identify studies by Wolfram (2005) and Fabrizio, Rose and Wolfram (2007) that conclude that generators in restructured jurisdictions have seen greater efficiency than their counterparts in the non-restructured jurisdictions in the US. They also reference Douglas (2006) as indicating that in the aftermath of regional electricity market restructuring, there has been an increase in the capacity utilization of low-cost coal-based generators compared to high-cost coal-based generators, leading to cost savings of between 2 and 3%.

Other studies that connect the change in capacity utilization ratios with restructuring cited by Blumsack et al (2008) include Blumsack and Lave (2004) and Zhang (2006), who attribute the increase in the capacity utilization rates of nuclear based electricity plants to restructuring. In terms of efficiency gains as gauged through a decrease in labour costs, they reference Niederjohn (2003) as indicating that employment has dropped by 29% in US jurisdictions that restructured their electricity markets, although they qualify this result with the point made by Apt (2005) that since labour costs only comprise 7% of total costs, the gains from savings in labour costs would likely be small. Having presented studies that in general conclude that restructuring has brought forth efficiency gains whether through increased capacity utilization ratios or through a decrease in labour costs, Blumsack et al (2008) also review studies, including those mentioned in Kwoka (2006), that investigate the impact of restructuring on electricity prices.

For this purpose, Blumsack et al (2008) divide studies into two types: those that investigate the impact of restructuring on wholesale electricity prices and those that study the impact of restructuring on retail electricity prices. According to these authors, these studies can also be classified based on the type of analysis (whether time series, cross sectional or panel) and also on the basis of the approach (whether prices are simply compared before and after restructuring, counterfactual electricity prices are determined, or a difference-in-differences approach is used focusing on the rate of change in electricity prices rather than on the electricity price level). Studies that focus on wholesale electricity prices include Synapse (2004) and Energy Security Analysis, Inc. ESAI (2005), both of which are also extensively reviewed in Kwoka (2006) as being among those studies that do not use an econometric-based analysis. Both of these studies focus on the PJM region, and whereas Synapse (2004) employs financial and operating data to determine counterfactual post-restructuring cost estimates for three companies in the PJM market, ESAI (2005) use a power flow model to investigate the impact of the PJM market expansion on wholesale electricity prices. Synapse (2004) concludes that during the first five post-restructuring years, deregulated cost rates have been lower than the rates that would have prevailed had regulation continued. Likewise giving a favourable view of restructuring, ESAI (2005) concludes that the expansion in the PJM market has not only brought in large amounts of low cost generation, but has contributed to a decline in electricity prices in the highest cost areas of the market.

According to Blumsack et al (2008), there exist a relatively larger number of studies that investigate the impact of restructuring on retail electricity prices. Three of these studies, which do not use an econometric based analysis, Centre for the Advancement of Energy Markets CAEM (2003), Global Energy Decisions GED (2005) and Apt (2005) have been reviewed extensively by Kwoka (2006). Whereas Apt (2005), mentioned earlier, uses a difference-in-differences approach, CAEM (2003) conducts simple pre- and post-restructuring price comparisons, and GED (2005), also mentioned earlier, simulates counterfactual generation costs and electricity prices. While the results from Apt (2005) and GED (2005) have been mentioned earlier, from a comparison of the jurisdictions that comprise the PJM market with the adjacent jurisdictions that continued regulation CAEM (2003) concludes, much like CERA (2005) that used an econometric framework, that the PJM market restructuring has saved consumers billions of real dollars in the first five years of the post restructuring period.

Blumsack et al (2008) note, as does Kwoka (2006), that while studies conducted by the industry and consultants report price savings from restructuring, studies conducted by academics do not find any evidence of a connection between lower electricity prices and electricity market restructuring. Blumsack et al (2008) reference Zarkinau and Whitworth (2006) and Zarkinau, Fox and Smolen (2007) that indicate that retail electricity prices for both residential and commercial consumers have increased in those areas in Texas where retail competition has been instituted. Likewise, they reference Taber, Chap and Mount (2006), who on the basis of estimating a Generalized Autoregressive Conditional Heteroskedasticity GARCH model for four classes of electricity prices – residential commercial, industrial and overall average prices – for the US from 1990–2004, and using utility level data, conclude that there does not seem to be evidence that electricity market restructuring has led to lower retail electricity prices.

Based on the above review of the literature it does not seem that a definite conclusion on the impact of restructuring on retail electricity prices has been reached in any particular jurisdiction. In the next section, we review studies that have investigated the impact of restructuring on electricity prices in Alberta.

3.5. Models in the Alberta Context

The studies reviewed above have mostly been conducted in the US context. As far as the Alberta electricity market is concerned, only Wellenius and Adamson (*W&A*) (2003) calculate counterfactual electricity prices. However, the W&A study is couched in a COS framework that requires information on the various cost inputs for the post-restructuring period, which are in general not publicly available. Perhaps a greater issue is the validity of using those cost inputs for electricity price forecasting as such cost inputs already have the effect of restructuring captured within them. Therefore, it would be naïve to employ them to find what prices would have looked like in the absence of restructuring. This issue is considered further in Chapters 4 and 5.

Another issue that arises in employing cost inputs for determining electricity prices is that as the trend toward competition continues, the relationship between the cost of producing electricity and the price charged will change fundamentally (EIA, 1997b: 11). While electricity prices under competition are subject to the same factors that affect electricity prices under regulation (Brown, 2001), to the extent that changes in fuel costs, generating capacity shortages and demand patterns have a stronger impact on electricity prices under competition than under regulation (EIA, 1997b: 62, 83), the electricity price function will be changed as a result of restructuring. These issues with the W&A approach limit its applicability for our analysis. Additional comments pertaining to this study are reviewed in Chapter 5.

Studies other than W&A (2003) do not consider a structural model for Alberta electricity prices let alone determine counterfactual electricity prices. Most such studies are concerned with modeling the spot electricity price, that is, they focus on the wholesale level rather than at the retail level. For example, both Atkins and Chen (2002) and Xiong (2004) deal with mean reverting, time varying, jump diffusion models of Alberta spot electricity prices, while Hinich and Serletis (2006) focus on signal coherence spectral analysis of Alberta hourly spot prices. These approaches are not directly relevant to the type of analysis that is contained in subsequent chapters of this dissertation, which requires a structural model of the electricity price.

3.6 Model Estimation Issues

In addition to considerations of model specification and methodologies for the evaluation of the effects of restructuring on electricity prices, a number of estimation or implementation issues are also identified in several previous studies. These are discussed below.

3.6.1 Issues Identified by Kwoka (2006)

Kwoka (2006) raises a number of issues related to the studies that attempt to determine the potential impact of restructuring on electricity prices. He argues that comparisons of pre- and post-restructuring electricity prices within a jurisdiction, and of post-restructuring electricity prices across restructured and non-restructured jurisdictions, may be inappropriate if certain issues are not addressed, including treating restructuring as a discrete event, forecasting outside the sample period, and not accounting for rate freezes and stranded costs.

Considering competitive generation, open transmission access, and retail competition as part of an indivisible policy bundle may, according to Kwoka (2006), provide a distorted picture of the impact of restructuring. In other words, treating restructuring as a discrete event, as opposed to the outcome of a series of policy actions occurring over time, may not be appropriate in studying the impact of restructuring on electricity prices. To account for this, rather than simply stating whether a particular generator restructured or not, Joskow (2006) used the supply percentage from unregulated generators to determine the extent of restructuring. However, it is not clear how severe a problem it might be if this issue is not dealt with, and it is also not clear how to account for this issue in the context of an analysis that uses provincial data as opposed to generator-specific data, such as is the case in the later chapters of this dissertation.

Kwoka (2006) also states that estimating the electricity price model for both the pre-restructuring and post-restructuring time periods as a whole, using a dummy variable to separate the two, has the advantage of not only resulting in a greater number of observations but also of strengthening the predictive power of the model. Estimating the model using the entire time period, he argues, also takes into account the fact that the relationship between electricity prices and the non-policy explanatory variables may change in the post-restructuring period compared to the pre-restructuring time period.

However, the very fact that the relationship between electricity prices and non-policy variables may change post-restructuring necessitates the use of only the pre-restructuring time period for estimation, in order to keep the relationship between electricity price and non-policy explanatory variables in the post-restructuring period similar to that in the pre-restructuring period, so that any impact of restructuring on this relationship is removed in the computation of the counterfactual electricity price in the post-restructuring period. To look at this in another way, if the relationship changes in the post-restructuring period, it would be necessary to estimate a model that has multiplicative as well as additive dummy variables, which would be equivalent to estimating separate models for the two periods.

To account for stranded costs, competitive transition charges, which are short-term additions to electricity prices to recover stranded costs, are removed from the total electricity price (Fagan, 2006). However, the issue of stranded costs, as mentioned earlier, is irrelevant in the Alberta context because such costs have usually been associated with the nuclear power plants and also because in Alberta the opposite case of stranded benefits has been observed. According to Daniel et al (2006), the market value of the low cost generation plants in Alberta was expected to rise over and above the regulated return due to wholesale prices rising higher under a marginal cost-based pricing framework than what was required under the COS framework. In fact one motivation of the government underlying restructuring initiatives was to retain this increase in market value of the generation plants, defined as stranded benefits, through the auction in Alberta in 2000 of Purchasing Power Agreements.

Accounting for electricity price freezes or rate caps at the time of, or for a short period subsequent to, restructuring would require the use of a better electricity price series than the one that is available for use in the empirical analysis that is conducted here. However, this is an important issue that could usefully be addressed in future work, as a review of other studies indicates that when these mandated rate reductions, caps, and freezes are taken into account, the evidence shifts against restructuring leading to lower electricity prices. Recent studies such as Rosen et al (2007) state that between 2005 and 2006, while electricity prices increased by 7.6% in regulated states, they increased by 12.3% in restructured states after accounting for price caps in these restructured jurisdictions. In terms of specific jurisdictions, potential electricity rate increases in Maryland, Connecticut and Delaware of 72% and 50% in 2007 and 59% in 2006, respectively, resulted in legislation designed to allow phasing in these rate increases over several years.

Likewise, retail electricity prices in states like California, Maryland, Virginia, Illinois and Montana increased after an unfreezing of the electricity price (Lave et al., 2007a). The presence of Illinois in this list contradicts the finding of Carlson and Loomis (2008) which concluded, based on counterfactual electricity price changes determined by controlling for fuel price changes and capacity expansions, that Illinois consumers have benefited from restructuring. This indicates the importance of developing a model which takes into account fuel price changes and generation capacity, in addition to price caps and freezes, in reaching appropriate conclusions concerning the effect of restructuring on lowering electricity prices.

While aspects of the Kowka (2006) critique have been addressed to some extent in the model and estimation procedures that are used in this dissertation, Lave, Apt, and Blumsack (2007a) note that the Kwoka (2006) critique sets up criteria for evaluating the effects of restructuring that are so demanding that they are not currently, and perhaps could not ever be, met by any study.

3.6.2. Restructuring Expectations

In addition to the three principal issues identified by Kwoka (2006), as outlined above, another issue that is typically raised in the context of evaluating the effects of restructuring concerns restructuring expectations. Various studies suggest that the impacts of restructuring begin to be experienced before the actual implementation of restructuring initiatives because of changes in the behaviour of the affected utilities as they adjust to the anticipated changes brought about by the restructuring process. For example, regulated distribution companies may begin to adjust their debt-to-equity ratios to bring these in line with those of competitive firms as they understand that investors expect to see both regulated and competitive players in the industry on an equal basis (Philipson and Willis, 2006).

Apart from affecting debt-to-equity ratios, restructuring expectations may also impact capacity investments, although the impact on capacity expansions is not entirely clear. On the one hand, because greater profits are concomitant with greater size, utilities anticipating competition have an incentive to invest in capacity expansions (Green, 2006). On the other hand, uncertainty prior to the implementation of restructuring initiatives provides incentives to reduce investment in generation capacity (Brown, 2001). The net impact on capacity expansion depends on the relative strength of the opposing effects of restructuring expectations. In terms of the model that is estimated in subsequent chapters, to examine the possible impact of restructuring expectations on the results, sensitivity analysis will be conducted by estimating the electricity price model using alternative pre-restructuring periods that end at different times. Specifically, given that the post-restructuring period begins in 2001, the pre-restructuring sample period is varied from 1965 – 2000 to 1965 – 1997.

3.6.3. The Role of Natural Gas Prices

Another point that is typically made in various studies that examine the impact of restructuring on electricity prices is the need to control for non-policy variables, and in particular natural gas prices. It is typically argued by restructuring proponents that any observed increase in post-restructuring electricity prices is due to the higher level of natural gas prices that may have eroded any benefits of competitive pricing (Lesser, 2007). Although, in some cases, natural gas-based generation may account for as little as 6% of the total generation, because of marginal pricing in competitive markets, since the price of the marginal natural gas-based generator may set the market price, any spikes in natural gas prices will naturally contribute to increasing electricity prices quite significantly (Rosen et al., 2007). This then motivates the inclusion of the natural gas price as a control variable in the estimation of the electricity price model.

3.6.4. Electricity Prices

As discussed in more detail in Chapter 4, the Alberta electricity price series that is used in our empirical analysis was obtained by dividing the revenue received for the energy sold by electric utilities and industrial establishments for domestic use and for use by farm businesses. Electricity price series constructed in this manner, as opposed to extracting them from electricity bills to residential consumers, have also been used by some studies in the US context. Fagan (2005), for instance, constructs electricity prices by dividing total revenue by total sales and then obtains the real electricity price by dividing by the U.S. GDP (chained) price index. This approach of obtaining prices by dividing revenues by sales is also used in several studies to obtain natural gas prices (Arano and Blair, 2008). In terms of the choice between using real and nominal electricity prices, the methodology that is used here to model electricity prices involves mimicking the COS process that is used in the pre-restructuring period, and the outcome of this process is nominal rather than real prices. Also, in terms of forecasting in the post-restructuring period, over- or under-estimation of actual real prices could occur just because of errors in predicting inflation, and this could lead to erroneous conclusions concerning the relationship between actual observed prices in the post-restructuring period and those that would have been expected to prevail had restructuring not occurred. For these reasons, the model that is estimated in subsequent chapters utilizes nominal electricity prices.

3.6.5. Price of Labour

Since data on the hourly wage rate is often not available, the price of labour in the electricity market, especially in the US, is often measured as the average annual labour payment per employee (Vlachou et al., 1996). As discussed in Chapter 4, a similar approach is used here with Canadian data.

3.6.6. Generation Capacity Data

A cursory examination of generation capacity data reveals that capacity fluctuates both up and down in different years, which may seem odd given that capacity usually changes in lump-sum amounts and over longer time intervals than do, for example, fuel prices. This might be due to the data reflecting commissioning and decommissioning of power plants, especially since this volatility is also noted in electricity generation greenhouse gas emissions (Hanus, 2005).

3.6.7. Legislation and Technology

In determining the impact of restructuring on electricity prices, the role of restructuring is often confounded by contemporaneous technological change and/or environment-related legislation. The role of technological change and environment-related legislation in impacting electricity prices is often captured through the use of a time trend and a dummy variable, respectively. Arano and Blair (2008) use a time trend to capture the effect of technology in the US context, whereas Vlachou et al. (1996) use a time trend to capture non-neutral and scale-augmenting technological change in a regression analysis context. However, it is important to note that time trends may create multicollinearity problems if other variables are also trending. Neumayer (2004) uses a year-specific dummy variable to capture exogenous changes in emission technology. This approach of using a dummy variable can also be used to account for the effect of environment-related legislation.

3.6.8. Constructing the Counterfactual

Notwithstanding the Kwoka (2006) critique on treating restructuring as a discrete event, the pre- and post-restructuring periods in Alberta can be distinguished on the basis of the year when retail market restructuring was implemented. In the context of the model specification that utilizes information based on the data obtained from restructured and non-restructured US jurisdictions, the issue of the determination of the pre- and post-restructuring periods also needs to be addressed. Another issue that needs to be considered is the identification of those states that restructured and those that did not restructure their electricity markets.

The pre- and post-restructuring periods within restructured jurisdictions in the US can be distinguished on the basis of the year in which retail market competition is introduced. However, a common year needs to be identified to facilitate comparisons between restructured and non-restructured jurisdictions. Three different years can be considered in this regard. According to Joskow (2005), wholesale electricity markets were operational even prior to 1998 when restructuring initiatives were implemented, whereas Wolfram (2005) prefers the year 2001 to distinguish between the restructured and non-restructured eras because that is when several states had passed restructuring legislation. Another option is to use 1996 as the demarcation point, as this is when many states allowed entry of competitive electricity providers in the market (Kwoka, 2006). For the analysis conducted here, in situations where such a defining year is required, the year 1996 is chosen on this basis; this choice also maintains a balance of pre- and post-restructuring data points in the various samples, which facilitates statistical analysis.

In terms of identifying the restructured US jurisdictions, there appears to be some disagreement as to which US states are considered to have restructured their electricity markets. The US General Accounting Office GAO (2002) concludes that 24 states and the District of Columbia have enacted retail electricity market competition, but that only 17 states and the District of Columbia continue to implement retail access. In contrast, Fagan (2005), by accessing the data from US DOE Federal Energy Management program, identifies 24 states and the District of Columbia as having enacted electricity market competition, but he removes Arkansas, California, Montana, Oklahoma, New Mexico and Nevada, in addition to Alaska and Hawaii, from the list of 24 jurisdictions so as to focus on the long term impacts of restructuring. This leaves 16 restructured jurisdictions in contrast to both US General Accounting Office GAO (2002), which has 17, and even Fagan (2006) that deems 18 restructured states as moving forward with restructuring.

More complications arise in identifying restructured jurisdictions when other studies are considered. Showalter (2008) removes Illinois, Ohio, Pennsylvania and Virginia from the list of restructured states due to the presence of retail electricity price caps. However, in contrast to Fagan (2005), California is considered by Showalter (2008) to be a restructured state since it exposed residential consumers to competitive market pricing. Thus, according to Showalter (2008) only thirteen US jurisdictions are treated as having restructured their electricity markets.[7]

Based on these alternatives, it would be possible to rationalize (at least) three different classifications of US jurisdictions that have and have not restructured. In the analysis in Chapter 5, the most general definition is used, so that 24 US jurisdictions will be viewed as having restructured their electricity markets. In large part our interest in these US jurisdictions concerns the different values of the variables that may affect the electricity price in restructured compared to non-restructured jurisdictions, so that the presence or absence of price caps, or even whether the restructuring status of the jurisdiction may have changed again subsequently, is not as important for our purposes.

3.7 Summary

A review of the literature, predominately emerging from the US, indicates that restructuring efforts have been motivated by a variety of issues inherent in the cost of service or rate of return regulation framework, including overinvestment and the subsequent unnecessarily high costs passed on to consumers, disincentives to invest in new technologies, and little incentive to innovate and reduce costs. In some cases, another reason for restructuring has been the move toward reducing government involvement in the electricity sector to reduce public debt, perhaps due to subsidized fuel costs and preferential rates for funds provided

[7] The thirteen restructured jurisdictions include California, Connecticut, District of Columbia, Delaware, Massachusetts, Maryland, Maine, Michigan, New Hampshire, New Jersey, New York, Rhode Island, and Texas.

to the utilities. The existence of high electricity prices despite low fuel prices, inefficient electricity pricing that is not based on marginal costs, and pricing based on average costs that included costs of older more expensive plants also motivated restructuring efforts. The desire to shift investment decision risks from consumers to producers, to improve efficiency, increase innovation and introduce retail choice to consumers, as well as to avoid the risk of being left behind as other jurisdictions undertook restructuring are also likely to have been contributing factors. Finally, technological developments that allowed for the introduction of smaller generation plants and that allowed for the development of regional markets through advances in transmission lines contributed by making restructuring efforts more feasible.

On the basis of the studies reviewed by Kwoka (2006) and Blumsack et al (2008), it was found that there is a general tendency for studies conducted by the industry and by consultants to report price savings from restructuring, while studies conducted by academics do not generally find evidence of a connection between electricity market restructuring and lower electricity prices. Even in more recent studies, contrasting results are also reported. In terms of the methodological approach that is used, very few of the several studies reviewed by Kwoka (2006) and Blumsack et al (2008) determine counterfactual electricity prices through regression analysis. Three of the four US based studies reviewed by Kwoka (2006) that do determine counterfactual electricity prices through regression analysis suggest that electricity market restructuring has lowered electricity prices. Moreover, Blumsack et al (2008) indicate that while most studies have concluded that restructuring has led to efficiency gains, studies report conflicting evidence on whether restructuring leads subsequently to lower retail electricity prices.

To some extent, differences in the findings of the various studies might be explained by the failure of many of the studies to address any or all of the critiques leveled by Kwoka (2006), including treating restructuring as a discrete event, forecasting outside the sample period, and not accounting for rate freezes and stranded costs. However, it is perhaps not possible to address all these critiques, especially in the absence of detailed firm-level data. In any case, Kwoka's preferred method of estimation for the entire sample period and using a dummy variable to measure the effect of restructuring on electricity prices seems particularly naïve, especially given his observation that the relationship between the variables and the price may change because of restructuring. The likelihood that restructuring itself may have affected the values of some of the explanatory variables in the post-restructuring period, an issue apparently not recognized by Kwoka (2006) or by most other studies, also suggests that such an approach would be inappropriate. In any event, the model and analysis developed and applied subsequently in Chapters 4 and 5 attempts to deal with Kwoka's critiques, to the extent possible given data limitations, as well as to address various other issues pertaining to data and estimation that were identified by other authors. In particular, the alternative approach that is developed and applied in Chapter 5 represents the first known attempt to evaluate the effect of restructuring on electricity prices using a counterfactual approach that takes account of the possibility that restructuring itself may have affected the values of some of the explanatory variables in the post-restructuring period.

Chapter 4: The Effect of Restructuring on Electricity Prices: A Preliminary Approach

4.1 Introduction

Evidence that electricity prices in Alberta increased after electricity market restructuring cannot be conclusive in terms of determining whether it was the restructuring itself that caused electricity prices to increase. For example, it could be argued that electricity prices would have increased anyway, possibly due to higher natural gas prices – since natural gas is used in many plants to generate electricity – and that in fact Alberta electricity prices increased less than would have otherwise been the case because of the restructuring that occurred. Thus, in order to determine the effects of electricity market restructuring on electricity prices it is necessary to consider a different approach. The approach that is developed here involves determining what electricity prices would likely have been in the post-restructuring period if restructuring had not occurred, and then comparing these so called "counterfactual" prices to the actual prices that were observed in this period. If these counterfactual prices are higher than the observed prices, it would suggest that restructuring did help to keep prices lower than they would otherwise have been. However, if the counterfactual electricity prices are lower than the actual prices, this would indicate that the effect of restructuring – in terms of electricity prices faced by consumers – was to make these prices higher.

The key component of this approach is the determination of the counterfactual prices. The basic framework that is used here to obtain these prices involves the formulation and subsequent estimation of a structural model of the determinants of electricity prices in the period prior to restructuring. This estimated model is then used in conjunction with observed values of the relevant variables in the post-restructuring period to forecast the electricity prices that would have been observed in the post-restructuring period in the absence of restructuring. These forecast prices are then used as the counterfactual prices that are compared to the prices that were actually observed in the post-restructuring period. Of course a problem with this approach is that restructuring itself may have caused changes in the values in the post-restructuring period of some of the explanatory variables that are used to model electricity prices. For example, restructuring may have increased the share of natural gas-based electricity generation by making it more feasible to employ gas-fired plants in the absence of regulatory approval delays that may have been inherent in the regulated system. This complication – endogeneity of some of the explanatory variables in the post-restructuring period – is considered in Chapter 5.

Despite this simplification, the analysis in this chapter serves a number of useful purposes. First, the model of electricity prices that is developed and estimated for the pre-restructuring period is not affected by this endogeneity problem, and in fact continues to be utilized in Chapter 5 where this issue is addressed. Second, the analysis with this initial approach can be used to determine if there is *prima facie* evidence that electricity prices increased as a result of restructuring. Third, it provides a base case to which other specifications can be compared. For example, if it was thought that generation capacity would have been only 90% as large if there had been no restructuring, this modification could be made to values of the generation capacity variable in the post-restructuring period, and a new set of counterfactual electricity prices obtained. In this way, the effects of various variables that might be expected to have had different values in the absence of restructuring can be easily evaluated.

The outline of the remainder of this chapter is as follows. In Section 4.2., a structural model of the determinants of residential electricity prices in Alberta in the pre-restructuring period is developed. The data that are used to estimate the model, and which ultimately limit the form that the model can take, are described in detail in Section 4.3. The final estimating equation is specified in Section 4.4, where the estimation results are also presented. As well as the base model, various modifications to the estimated equation, the estimation method that is used, and the sample period that is used for estimation, are considered and applied where appropriate, particularly in terms of addressing issues associated with possible non-stationarity of many of the variables included in the analysis. The estimated parameters of the models are used in conjunction with observed values of the explanatory variables in the post-restructuring period to obtain forecasts of the prices that would have been expected to prevail in this post-restructuring period if restructuring had not occurred. These "counterfactual" prices are then compared to the actual prices that were observed in the post-restructuring period in order to evaluate the likely effects of restructuring on these prices. Finally, Section 4.5 contains a brief summary.

4.2. A Model of Alberta Residential Electricity Prices in the Pre-Restructuring Period

Typically, electricity prices are modeled using a time series approach, since the objective is often to forecast electricity prices in the future. The models that are used in this context are those frequently observed in times series analysis, such as ARIMA models, mean reverting models, GARCH models, etc. However, the approach that is required here involves structural modeling, since the aim is to compare forecasts for the post-restructuring period based on the model that applied before restructuring to actual values obtained subsequent to the restructuring, where the post-restructuring forecasts are based on actual values of the explanatory variables in the post-restructuring period.

Conceptually, there are at least two approaches that could be used in structural modelling of electricity prices in the pre-restructuring period. The first could be termed an accounting approach, in that it would be based on the cost-of-service (COS) regulation that was used to determine electricity prices in this period. Specifically, since a regulator determined the price of electricity by ensuring that it covered all costs, including a regulated rate of return, the only requirements of this approach are a list of the costs considered by the regulator, along with specification of the regulated rate of return. Then, in the post-restructuring period, electricity prices in the absence of restructuring could be forecast by adding these costs together, including the required rate of return, to determine required revenues, which would then be divided by the amount of electricity that was to be delivered. Unfortunately, in the post-restructuring period, in the absence of regulation, it is not possible to obtain data on costs, so that electricity price forecasts cannot be obtained in this way.

The second approach, used here, involves focusing on the main determinants of the price of electricity and econometrically determining their numerical importance in determining the price. Essentially this process views the regulator and regulation process that was in place prior to restructuring as being a veil that simply hides the individual roles of these variables. For example, the prices of fuels used to generate electricity are likely to be important determinants of the price of electricity itself. From a regulator's viewpoint, all that is required is the cost of fuels, which is added to other costs, etc. However, for our purposes it is necessary to quantify the role of each fuel price, since then fuel prices in the post restructuring period can be used along with the values of other relevant variables to forecast the electricity price in this period. To our knowledge, no one has yet conducted this kind of analysis for Alberta since, as noted earlier, most of the models employed in the context of electricity prices are usually of the ARIMA and GARCH type.

4.2.1 Electricity Price Determinants

4.2.1.1 General Framework

A key requirement in determining the structural form for a model of electricity prices in the pre-restructuring period is the identification of the relevant variables. However, in view of the forecasting that is to be undertaken, the variable selection must be guided by the likely availability of data in both the pre- and post-restructuring periods.[1] Of course there are also a number of other issues that must be addressed, such as determining the appropriate functional form, etc.

The approach that is used here to structurally model electricity prices is akin to a production function, in which various inputs are combined to produce output. Here the "inputs" are the various components of costs, while the "output" is the electricity price. Of course, it is also necessary to control for the effects of various other factors that may affect the relationship between these costs and the price. Nevertheless, as a first step in identifying the main determinants of the electricity price, it is convenient to focus on the main components included in the cost of service approach. This suggests that the main determinants of the

[1] To the extent that important variables are omitted due to lack of data, the estimation could be biased. Unfortunately, there is no apparent solution to this problem.

electricity price would include capital and installation (C&I) costs, fuel (F) costs, and operation and maintenance (O&M) costs.[2]

Specifically, using R to denote utility revenue (or the revenue requirement), we have:

(4.1) $$R = C\&I + O\&M + F$$

Continuing with this approach, electric utility revenue could be divided by the amount of electricity sold,[3] Q, yielding average revenue per kilowatt-hour of electricity sold (The Electricity Forum, 2005), which is often used as a proxy for the retail price of electricity.[4] Thus, the electricity price, P, which is frequently expressed in dollars (or cents) per kilowatt-hour, and which under COS regulation would equal the average cost, could be represented by the following equation.

(4.2) $$P = C\&I/Q + O\&M/Q + F/Q$$

While this may be a useful representation of electricity prices, since, as noted previously, the cost components on the right hand side of this equation are generally unknown following restructuring, it will not be possible to use an equation of this type to forecast electricity prices in the post-restructuring period. An additional issue with this approach, which is also relevant for the empirical analysis that follows, concerns the definitions of the variables on the right-hand side of (4.2). As shown, to obtain (4.2) from (4.1), all cost measures are divided by Q, so that these terms are all measured in units of costs per unit of output. This is consistent with the values of the variables contained in the various financial tables that are available under the COS approach in the pre-restructuring regulated period, which are typically expressed in terms of cost per unit of electricity rather than cost per unit of input. For example, a fuel cost of $x per kWh (rather than $y per tonne or per cubic metre) indicates that $x is the fuel cost that is incurred to generate one kWh of electricity. However, this type of cost information cannot be used for forecasting, since it requires knowledge of the cost of fuel per unit of electricity in future periods (after restructuring) – that is, the total cost of fuel and the quantity of electricity – not just the price of fuel in these future periods (which is generally known). In addition, it causes endogeneity problems for the analysis. In particular, to assess the effects of restructuring on the electricity price, our approach involves determining whether and to what extent the relationship between the input prices and the electricity price changed following restructuring. However, if input prices are measured as cost per unit of electricity, then these input prices may change due to changes in the quantity of electricity or in the quantities of inputs used, or due to restructuring itself. Thus, with this type of

[2] See, for example, NZ Ministry of Economic Development (2005), U.S. Congressional Budget Office (2003), and The California Energy Commission (2002).

[3] Of course, focusing on consumers it would be necessary to isolate those costs (expenditures) and revenues attributable to this specific sector, but we ignore this complication for now.

[4] See, for example, EIA (2000b:9).

data it would not generally be possible to disentangle the effects on the electricity price that are due to changes in the price of each input per-unit of that input from those that are due to restructuring.

To use the price per unit input of each type of input in the modelling of electricity prices, it is necessary to define the input prices that underlie the various costs identified in (4.1). Thus, for example, the unit price for capital cost could be represented by the user cost of capital, the unit price for operation and maintenance costs could be represented by the average wage paid for labour, and coal and natural gas prices could be used to represent fuel costs, which in Alberta predominantly comprise expenditures on these two fuels. The importance of fuel prices and labour wages can be gauged from studies conducted in the US, which indicate that fuel costs are the largest component of operation and maintenance costs, while labour costs and rents are included in other O&M costs (EIA, 1997b:17). Non-fuel costs are largely labour related, with the utility industry generally being highly unionized (EIA, 1997b:68). Although these non-fuel costs clearly contribute to the price of electricity, it would appear to be most important to focus on the fuel prices in view of evidence that fuel costs account for approximately two-thirds of utility power production expenditures (EIA, 1998:3). Thus, based on this approach, (4.2) would be replaced by a specification such as:

(4.3) P = f(user cost of capital, wage rate, coal price, natural gas price),

where f(.) is some functional specification that would need to be determined.

Modelling the electricity price by mimicking the cost of service method, as in (4.3), ignores other variables of interest that could possibly be affecting the electricity price, such as capacity utilization, economic growth, etc. Thus, the electricity price function, as defined in (4.3), needs to be augmented by other relevant variables so that we can control for their effects on the electricity price. These additional variables are identified through a review of the literature on electricity industry and electricity industry restructuring (Chapter 3), as well as information pertaining to the electricity industry in Alberta (Chapter 2), which is briefly summarized in the following subsections.

4.2.1.2 Capacity Utilization, Economic Growth, and Weather

A number of other factors have been found to be important determinants of the electricity price (and electricity price forecasts) in other jurisdictions, with the particular factors differing depending on whether forecasts are short-run or long-run, as well as on the frequency of the forecasts. In particular, weather has been found to be an important short-run determinant of electricity prices, whereas cost and performance of new generating capacity, economic growth, and environmental regulations are important determinants of long run forecasts (Hanser, 1998). While seasonal price variations have been found to be influenced by natural gas prices and weather, spot market volatility is influenced more by forced generation outages, generation fuel mix, transmission congestion and weather (Down et al., 2003b:4). Future trends in electricity prices are expected to depend on capacity, weather, fuel prices, electricity use, and electricity generation, transmission and distribution costs (EIA, 2004).

Of these factors, capacity, weather, and electricity use are not yet explicitly incorporated in our model formulation.[5] Obviously capacity constraints may affect the electricity price – since capacity cannot be readily varied, the price might be expected to increase as demand approaches capacity. This suggests that rather than generating capacity, the model should include generating capacity utilization to reflect the tightness in electricity supply. However, there may also be a separate role for capacity itself, since the costs associated with this capacity and its maintenance would be expected to be reflected in the electricity price. On similar grounds it may also be important to control for high electricity demand, or growth in electricity demand, because of the likely effect this will have on the electricity price due to capacity constraints. Economic growth could be used to capture this effect, although it may be partially captured already through the capacity utilization variable. Together, the capacity utilization and economic growth variables would be expected to capture the predominant effect of capacity constraints, and as such may also account for outages resulting from such constraints or other congestion.

In terms of the weather variable, this may be less important in a model here, which is based on annual data, although general weather patterns in different years, for example due to the El Nino and La Nina effects[6], could cause substantial variations in levels of demand, which may affect the electricity price. Although there are many dimensions of weather, the limited number of annual observations in the pre-restructuring period limits the number of explanatory variables that can be included in our model. One possible variable that could be used in the context of Alberta is the number of heating degree days (HDD) per year. While natural gas rather than electricity is primarily used for heating in Alberta (although with forced air furnaces, electricity is also required for this purpose), higher values of HDD reflect colder temperatures, which may induce an increased level of indoor activities, which may be accompanied by increased electricity use.

[5] These variables may not have an obvious role to play in determining the electricity price under COS Regulation, but since we do not have full information available on costs, factors that may act as proxies for the effects of some of these other variables are required.. Also, since these variables might play a role in price determination in the post-restructuring period, they are considered for inclusion in the model.

[6] El Nino and La Nina effects arise as a consequence of warmer and cooler than usual water on the West coast that respectively lead to warmer/drier and cooler/wetter than normal winters in southern Canada from the BC west coast to the Great Lakes (Environment Canada, 2010).

4.2.1.3 Heat Rates

The plant heat rate is a measure of generating station thermal efficiency. It is computed by dividing the total BTU content of fuel burned for electric generation by the resulting net generation, and therefore reflects the amount of energy required to generate one-kilowatt hour of electricity. The market heat rate, calculated by dividing the market price of electricity by the market price of natural gas (the marginal fuel), provides a measure of the efficiency at which power plants should be run (Institute for Energy, Law and Enterprise, 2003: 22). Thus, while the plant heat rate refers to the thermal efficiency of a plant, the market heat rate indicates the level of efficiency at which generators ought to be run.

Plants that have heat rates less than the market rate are the most efficient, and should therefore have an advantage in terms of the variable cost of electricity generation. In a competitive environment, such as where plants bid to provide electricity to a central clearing house, like the Power Pool in Alberta, these plants would require lower prices to cover their costs and would typically be used first to generate electricity. Thus, it is not surprising that the US Energy Information Administration (EIA) specifically associates improvements in heat rates with competition (Burtraw et al., 2000:28). Post restructuring, generators will have an incentive to minimize fuel use by improving heat rates, which in turn could also reduce carbon emission rate per kWh (Palmer, 1999:5).

There are three main reasons why it may be important to include heat rates in the model. First, they reflect technological innovation, which might be expected to have a direct impact on electricity prices. Second, since restructuring affects technological innovation and hence heat rates, it would be important to control for this effect in the post-restructuring analysis. Third, it is important to distinguish between the effects of restructuring and technological developments on electricity prices, which can be done by specifically including the heat rate in the model.

4.2.1.4 California Prices

The report by Alberta's Market Surveillance Administrator indicates that the BC-Alberta transmission limitation causes high and volatile prices during times of constrained supply in Alberta (Woo et al., 2003:1114). In addition, according to Jaccard (2002:21), Pool prices exhibited a sudden rise immediately after the Purchasing Power Arrangements Auction in Alberta in 2000, because of rising natural gas prices, BC hydro buying power from Alberta and selling it to California, and because of bidding strategies of influential suppliers. This suggests that it might be important to capture the BC–Alberta electricity trade since it may impact the Pool price. However, given that Alberta changed its wholesale pricing system to exclude imports and exports from setting pool prices in November 2000 (Trebilcock and Hrab, 2004:55), and since the interconnection between Alberta and BC has relatively low capacity,[7] and in view of the limited number of explanatory variables that can be included in the electricity price function due to the short pre-restructuring period for which data are available, Californian electricity prices are not included in the model.

4.2.1.5 Summary

In view of the preceding analysis, a general specification suitable for an electricity price determination equation for Alberta is as follows:

(4.4) Electricity price = *f* (coal price, natural gas price, generating capacity, generating capacity utilization, annual wage rate, user cost of capital, heat rates, economic growth (electricity demand), weather)

This model specifies the determinants of the electricity price in a functional specification that is analogous to an augmented production function. It is important to note, however, that there are a number of other variables that have been suggested in various other studies that may be important determinants of the electricity price. These have been omitted here due to the limited number of variables that can be included given the short period of data availability, the desire to keep the model as simple as possible by focusing on the primary variables, and the belief that some of these effects may be captured by variables already included in the model. Examples of possibly relevant omitted variables include the volatility (rather than just the level) of the natural gas price – many proponents of restructuring have argued that electricity prices would have increased even in the absence of restructuring due to higher and more volatile natural gas prices – as well as excess supply (supply-demand), which may capture the effect of power shortages on electricity prices, although this latter effect may be adequately reflected in the capacity utilization variable that is included in the above specification. These factors, to the extent that they are relevant enter the model through the random error term that will be included in the specification that is estimated.

4.3 Data

Data used to estimate the electricity price model are obtained from a variety of sources. A detailed description of the variables and data sources is provided below. Although observations on some variables are available on a more frequent basis, the data frequency is limited by the fact that data for some variables are only available annually. Since the data do not extend prior to the early 1960s for some of the variables, and since structural breaks may be evident

[7] According to Daniel et al. (2006), by the end of 1995 the interconnections to BC and to Saskatchewan jointly provided only about 550 MW of electricity, which represented about 6% of Alberta's generation capacity.

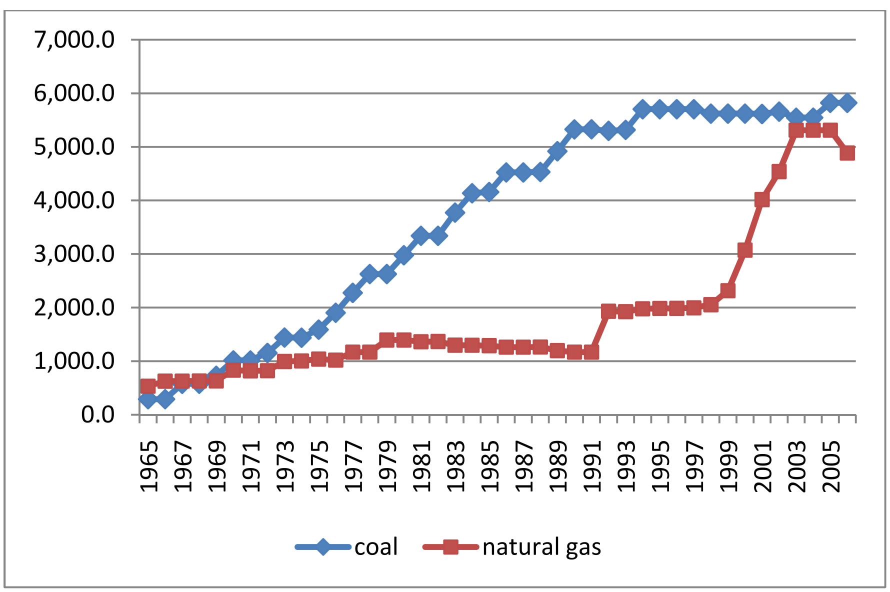
for earlier data, the pre-restructuring period of analysis that is used here begins in 1965. Also, since the effects of the restructuring process began to surface in 1998, even though retail competition was not actually introduced until 2001, the pre-restructuring period model is initially estimated using annual data for the period 1965 to 1997, although sensitivity analysis with respect to the end point is used to ascertain the importance of this choice.

4.3.1 Generating Capacity

There are two main sources of data for generation capacity, EPS *(Electric Power Statistics)* and AEI (*Alberta Electric Industry Annual Statistics*). EPS data for this variable include the sub-components hydro, steam, internal combustion, and gas turbine, while the AEI sub-categories are hydro, coal and gas. Both data sources include data from the mid 1960s, with the AEI data available from 1964 and the EPS data since 1965. Although EPS is used as the source for a number of other variables, so that for consistency it may be desirable to also use this source for generating capacity data, the AEI generating capacity data are used here in view of their more convenient structure, as the AEI subcategories more closely mirror the fuel price categories that are used here (Section 4.3.3).

As shown in Figure 4.1, coal-based generation capacity exhibits an upward trend until 1994, which predates the onset of restructuring in the late 1990s, and after this time remains relatively constant. Natural gas-based generation capacity experiences a rising trend approaching the coal-based generation capacity, which could possibly be attributed to either restructuring or technological developments. While coal-based generation capacity is generally much higher than natural gas-based generation capacity, it is interesting to note that in the late 1960s, it was slightly lower than its natural gas counterpart.

Figure 4.1: Alberta Electricity Capacity (MW)

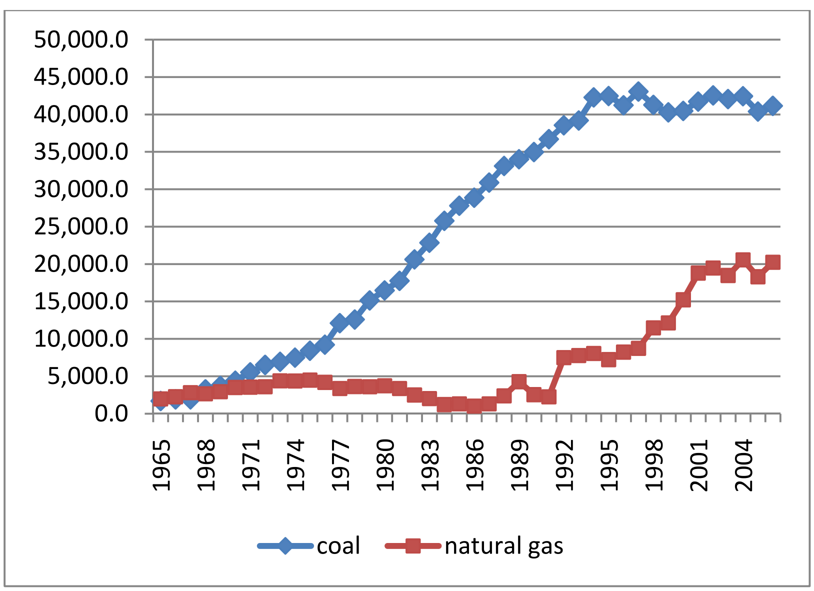


4.3.2 Capacity Utilization

There are two available measures of capacity utilization, namely the ratio of peak demand to total generation capacity and the ratio of generation to generation capacity. These two variables reflect different aspects of capacity utilization. The ratio of peak demand to total generation capacity indicates how close the system is to total capacity in peak periods, while the ratio of generation to generation capacity indicates average capacity utilization over a particular period, in this case one year. Therefore, it might be expected that the former ratio, involving peak demand, might be a better indicator of the tightness of the generation system. Unfortunately, data on peak demand, contained in the publication *Electric Power in Canada*, are only available from 1985 to 1998.[8] Therefore we utilize data on generation and generation capacity, available since 1963 from AEI, in order to construct an average capacity utilization variable. One advantage of this data source is that since the AEI data are disaggregated on the basis of coal- and natural gas-based generation, these subdivisions can be employed to calculate ratios that indicate the separate capacity utilizations of coal- and natural gas-based plants.

Data for generation that, like those for capacity, were extracted from AEI, are shown in Figure 4.2. This figure indicates that after rapid growth, coal based generation reached a plateau after 1994, whereas natural gas based generation showed a marked increase after 1991. This seems to indicate that the trend in rising natural gas based generation had started much before restructuring initiatives, although restructuring expectations might explain the sharp rise in natural gas based generation after 1997.

Figure 4.2: Alberta Electricity Generation by Fuel Source (GWh)

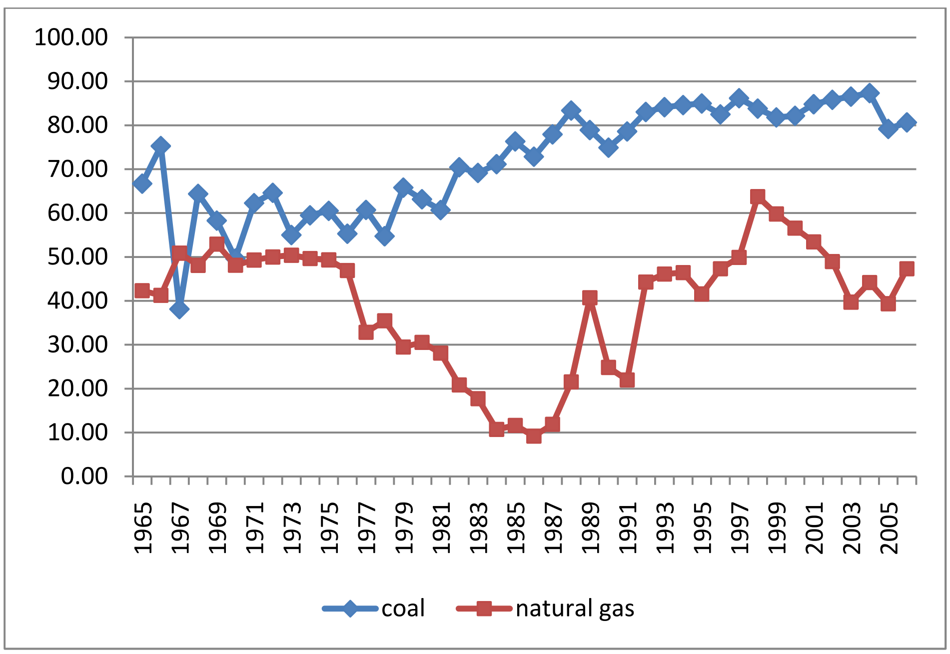


[8] Prior to 1985 data are only available for specific years: 1960, 1965, 1970, 1975 and 1980.

Coal- and natural gas-based utilization ratios were computed by dividing the respective generation figures (measured in GWh) by capacity data (measured in MW). The annual capacity data, in units of MW, were converted to MWh by multiplying by 8760, and after converting both generation and capacity figures to common units, the coal and natural gas based capacity utilization ratios were determined as percentages.

Figure 4.3, which displays the AEI-based coal- and natural gas-based capacity utilization series, reveals that coal-based utilization has been increasing rapidly compared to natural gas-based capacity utilization, which had actually started declining prior to resurgence in the early 1990s. However, post 1991, natural gas-based capacity utilization started increasing dramatically whereas coal-based utilization had effectively reached a plateau, reflecting the general trend in terms of a shift from coal-based capacity and generation toward natural gas-based capacity and generation. While this trend had begun in the early 1990s before any restructuring initiatives, the drop in natural gas based capacity utilization after 1998 reflects the spike in natural gas-based capacity (Figure 4.1) relative to natural gas-based generation (Figure 4.2), which is suggestive of the role of restructuring expectations in influencing investment in natural gas-based generation capacity.

Figure 4.3: Capacity Utilization (%)



4.3.3 Fuel Prices

4.3.3.1 Natural Gas Price

Data on average natural gas prices were calculated from EPS data by dividing the cost of natural gas used for generating electricity for electric utilities by the quantity of natural gas used for this purpose. From 1965 to 1973, the natural gas quantity is measured in units of MCF (million cubic feet), whereas from 1974 onwards the unit of measurement is thousand cubic metres. Using the conversion factors of 1 MCF = 28.317 cubic metres (Rowlett, 2003) and 1 GJ (gigajoule) = 26.8 cubic metres (Alberta Government, 2011)[9], we obtain a price measured in $/GJ.

There are a number of other sources of natural gas price data for Alberta, but these were rejected for a variety of reasons. The Alberta natural gas reference price (ARP), determined by the Alberta Department of Energy through a survey of actual sales transactions, is primarily used for royalty purposes rather than as a reflection of the actual price of natural gas faced by electricity generators.[10] Another alternative is the industry price index for natural gas produced by Statistics Canada, but this refers to prices across Canada rather than those experienced specifically in Alberta. The daily average spot price of natural gas at the AECO-C hub in Alberta could also be used, although these Alberta natural gas trading prices are not available before 1990.[11] In any event, these prices are highly correlated with the prices obtained from EPS that are used here (correlation = 0.92 for the period 1990 to 2002). Prior to AECO-C, the Empress natural gas price from the Empress Natural Gas Market Center could be used, but these prices extend back only until 1986 when this Center was established (Tobin, 2003). Finally, natural gas industry prices from 1978 to 2001 in units of $/toe (tons of oil equivalent) could be obtained from the Enerdata database,[12] but in view of the short period covered and the additional conversion that is required, these data were not considered further.

Along with the series from EPS that is used in the subsequent empirical analysis, the natural gas prices obtained from these different sources (ARP from AEUB, as well as the AECO-C series and the Industry Price Index from Statistics Canada) are presented in Figure 4.4 for the period 1990 to 2002, when they are all available. This figure indicates that the different price series generally follow similar trends, with a sharp rise in 2001 and declining subsequently, although the EPS series spikes one year earlier in 2000.

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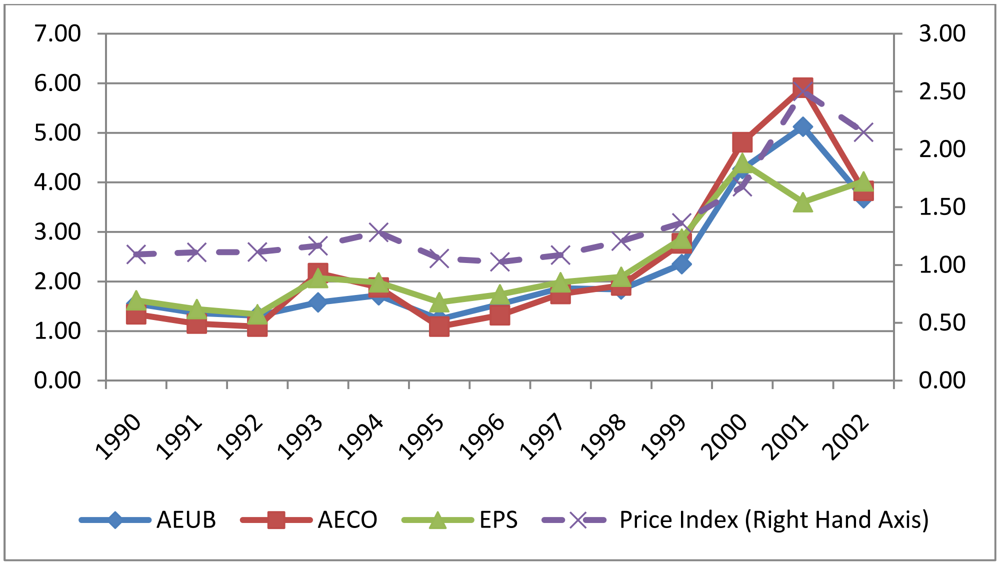
[9] See http://www.energy.alberta.ca/About_Us/1132.asp#Natural_Gas

[10] See, for example, http://www.energy.alberta.ca/NaturalGas/725.asp

[11] Natural Resources of Canada, Energy Use Handbook Tables provide data starting from 1990. Another indication that the AECO/NIT natural gas market center was formed in 1990 is in http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/market_hubs/mkthubsweb.html.

[12] Enerdata Ltd. provides natural gas price indices and spot and future prices on Canadian and US markets.

Figure 4.4: Natural Gas Prices from Various Sources



Measured in units of $/GJ except for the natural gas price index

4.3.3.2 Coal Price

Data on average coal prices were calculated from EPS data by dividing the cost of coal that was used for generating electricity for electric utilities by the quantity of coal used for this purpose. The coal quantity is measured in units of short tons from 1965 to 1973, in metric tons from 1974 to 1984, and in units of Mg from 1985-1998. Using the conversion factors of 1 metric ton = 1.1023 short ton,[13] 1 Mg = 1 metric ton (Rowlett, 2003), and 1 Mg = 24.1369226 GJ,[14] we obtain a price measured in $/GJ. These values are displayed in Figure 4.5.

An alternative series for coal prices is the Western coal price, available in *Electric Power in Canada* (EPC) from 1969 to 1998. These prices are measured in units of mills/kWh, and since mills are 0.001$ (Rowlett, 2003), the unit effectively is $/MWh. This series is also displayed in Figure 4.5 after converting the units to $/GJ. Although the western coal price is generally greater than the EPS coal price, the two series have a correlation of 0.9955 from 1969 to 1998.[15] This western coal price series could be used rather than the EPS coal price series,

[13] This conversion factor was calculated from the overlapping years, which contained data based on both short ton as well as the metric ton. Given this factor, the earlier data based on short ton was converted to metric ton units.
[14] This conversion factor is from
http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics
[15] It is unclear why EPS coal prices (converted from $/Mg units to $/GJ units by dividing by 24.137) are so much less than western coal prices, which are converted from $/MWh units to $/GJ by dividing by 3.6.

but the EPS series was selected since this would be consistent with the natural gas price series that is used (see previous section) and the western coal price, expressed as $/MWh, is expressed in terms of electricity output.[16] Other possible sources for coal prices, including the Statistics Canada industry price index for thermal coal purchases, which is for Canada rather than Alberta, and the Enerdata database,[17] were not considered further.

Figure 4.5: Alberta Coal prices ($/GJ)

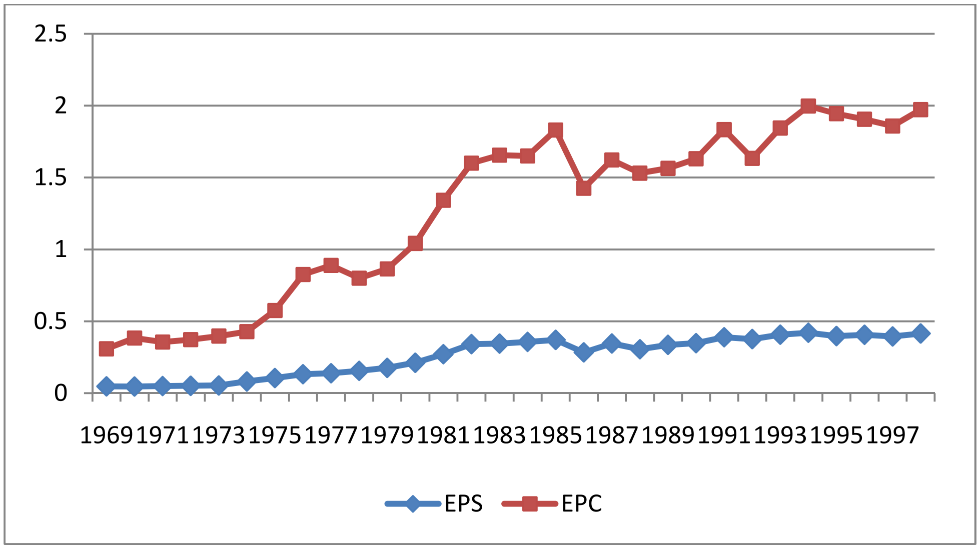
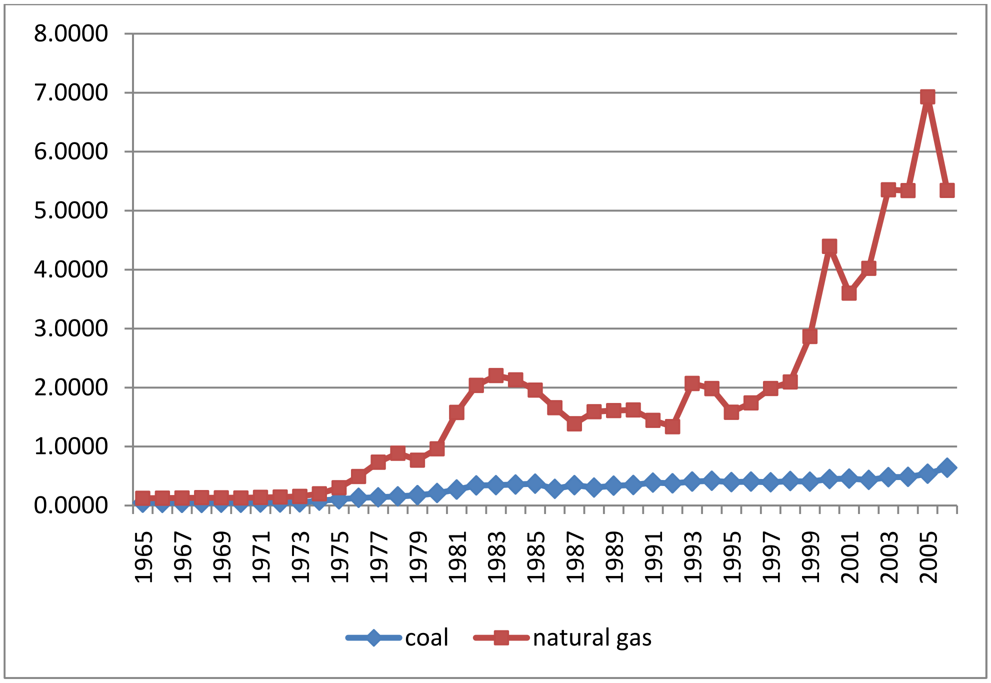


Figure 4.6 contains the complete EPS coal and natural gas price series for Alberta from 1965 to 2006. Figure 4.6 indicates that since 1975, natural gas prices are much higher and more volatile when compared to coal prices from the same source and in the same units. Comparing natural gas prices with natural gas capacity, shown in Figure 4.1, a rising trend in natural gas-based capacity, despite the rising trend in natural gas prices in the late 1990s, is apparent. This seems to suggest that natural gas-based capacity is a more important determinant for electricity generation than are natural gas prices. In contrast, coal-based capacity and coal prices seem almost unrelated.

[16] This could be converted to $/GJ using the conversion factor 1 MWh = 3.6 GJ from www.unc.edu/~rowlett/units.

[17] The issues with using coal prices from the Enerdata database are similar to those pertaining to natural gas prices, noted in Section 4.3.3.1.

Figure 4.6: Alberta Coal and Natural Gas Prices ($/GJ)



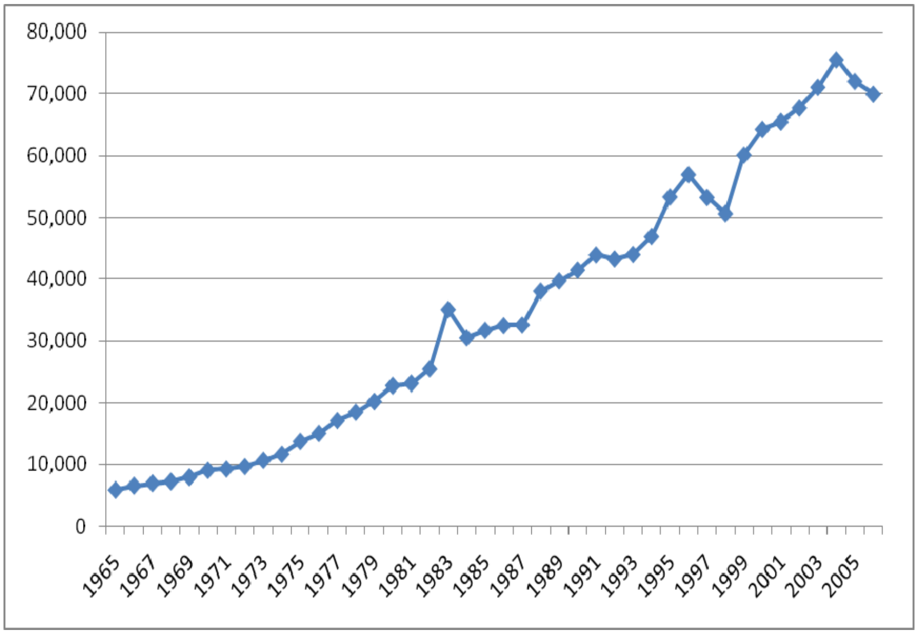
4.3.4 Price of Labour

According to EPS, the costs of Operations, Maintenance and Administration comprise salaries and wages, supplementary employee benefits, the cost of fuel, the cost of material used, the cost of purchased services, the cost of repair and maintenance, royalty expenses, indirect taxes, and other. Fuel expenses, which are by far the largest component of these costs, were considered in the previous section. In view of limitations on the number of explanatory variables that can enter into the electricity price determination equation (4.4), due to the relatively short time pre-restructuring time period that is used for estimation, as well as the fact that some categories of costs are relatively small and/or have no available data, we focus on per-unit price of labour (annual wages per employee) since labour is the next largest remaining component of operations and maintenance expenditures.

Although prices for this and various other components of electricity provision could be obtained by taking expenditure data on these components from EPS, dividing by electricity generated to obtain $/KWh figures, and then converting these to $/GJ using appropriate conversion factors, this approach yields costs per unit of electricity generated, which is not in the form we require. Rather, we require data on the per-unit costs of the inputs in their natural units.

Annual wages per employee, calculated from EPS data by dividing annual wages by total employees, are displayed in Figure 4.7. These data show a steady upward rising trend, with the exception of 1984 and also 1997 and 1998 when the annual wage per employee actually fell, although in both cases following larger than usual increases in the preceding year(s). While the decline in annual wages per worker in 1997 and 1998 might be attributed to restructuring expectations, the decline in 1984 serves as a counterpart in a regulated setting.[18]

Figure 4.7: Annual Wages per Worker ($/worker)



4.3.5 Price of Capital Services

The user cost of capital involves three main components – interest expense, depreciation expense and expected capital gains, all appropriately adjusted to reflect tax considerations. In generic form this can be written as: [19]

$$ucc_t = p_{kt}(r_t + \delta_t - \dot{k}_t / k_t)(1-t) \tag{4.5}$$

where ucc_t is the user cost of capital (price of capital services) at time t, p_{kt} is the unit price of capital, r_t is the interest rate, δ_t is the depreciation rate, $\dot{k}_t / k_t$ is the expected rate of capital gains, and *t* is the tax rate that applies to these costs.

[18] In contrast, for the Alberta economy as a whole, a broad definition of Average Weekly Earnings (AWE) – for the Industrial Aggregate, for all workers, including overtime (CANSIM Series V302121) – increased by 2.1% in 1984 and by 2.4% and 2.1% in 1997 and 1998.

[19] See, for example, Boadway, Bruce and Mintz (CJE, 1984).

The problem with this formula for operational purposes is data availability. Within a particular firm, much of the information that is required to calculate the user cost of capital, as in (4.5), might be expected to be known, but to a researcher it is simply unavailable. For example, the unit price of capital could be constructed from the ratio of the capital stock in nominal and in real terms, but this is not available. Of course, calculation of expected capital gains is problematical if the value of the capital stock in each year is not known. Share prices could be used, although these would include other assets of the firms, which might involve very different capital appreciation components. In the absence of other information, it is perhaps not unreasonable to assume that expected capital gains are zero. Depreciation rates are clearly important and are unlikely to be equal to zero, as are tax rates. Attempts to determine both depreciation and tax rate components of the user cost of capital formula were made based on the financial statements of the three principal utilities, TransAlta, EPCOR and ATCO, for 1974-2004 (depreciation rates) and 1980-2004 (tax rates), as detailed in Appendix 4.1. However, these calculations are plagued with missing data and the need to make a large number of assumptions, and in any event could not be determined prior to 1974, which effectively prevents their use in the empirical estimation here which begins in 1965.

In terms of the interest rate component of the user cost of capital, since the generators are long-term assets and financial statements of electricity utilities refer to long-term debt, we use an interest rate that applies to long-term debt. There are two obvious sources for such an interest rate, one being *Electric Power in Canada* (EPC) and the other being Statistics Canada's electronic database, CANSIM. Five interest rate data series on long-term bonds were considered from CANSIM, of which one series, V122487 (Government of Canada Marketable Bonds, Average Yield over 10 Years) was selected as the other series did not provide data for the entire 1965 to 2006 time period. However, for the period for which there were available, these different interest rates were highly correlated, as is also detailed in Appendix 4.1.

Interest rates were also computed based on the financial statements of the three utilities, as detailed in Appendix 4.1, but again with severe caveats, including limited and sporadic data availability, and the limited time period from 1974 to 2004. The correlation of the average interest rate computed from the financial statements with the EPC interest rate series and with the CANSIM interest rate series was 0.395 and 0.592, respectively, for 1974-1999. Despite these relatively low correlations, the limited availability of the average interest rate series based on the financial statements, along with caveats concerning its use – including weighting issues and the difficulties involved and assumptions required to construct a consistent set of numbers from yearly annual reports especially given the structural changes that have occurred with electric utility companies – preclude its use in the subsequent empirical analysis.[20]

[20] Despite the assumptions and limitations on the component series, as described previously, an attempt was made to construct a user cost of capital series, to the extent possible, based on these

As an alternative, based on the finance literature, the weighted average cost of capital (WACC) was also determined for 1988-2006 based on the utilities' financial statements, *Financial Post* bonds data and other sources, details of which are also provided in Appendix 4.1. The WACC is defined as the weighted average cost of raising a dollar of capital at the margin, which includes both bonds and equity. It does not reflect the average cost of capital raised in the past or even the average cost of capital. While the current yield on bonds is used in computing cost of debt as opposed to the coupon rate (Lockett, 2002), various methods are used to compute the cost of equity, namely the Capital Asset Pricing Model (*CAPM*) based equity risk premium method, discounted cash flow (*DCF*) model and the bond yield plus risk premium approach (Brigham and Gapenski, 1997). The comparable earnings method is also used, although it is sensitive to the accounting practices of the utilities selected for comparison, the business cycle selected for the method, as well as the discontinuities caused by events such as mergers, divestitures or restructuring. Likewise, the issues involved with the DCF model include the validity of the growth rate used in the model and the volatility of the growth series selected for the model (AEUB, Decision U99099).

In this case, the correlation between the WACC series, calculated in Appendix 4.1, and the selected long-run interest rate from CANSIM for 1988-2006 was 0.974, so that the two series track each other reasonably well, as shown in Figure 4.8. Like the interest rate on long-term bonds, the WACC has been generally declining since 1990, including over the post-restructuring period, suggesting that the price of capital services did not increase due to any volatility or uncertainty in this latter period. Thus, even though, as observed earlier, natural gas prices were quite high and volatile after 1998, the opposite appears to be the case for the cost of capital services, which may partially explain the apparent increased investment in natural gas-based capacity despite high and volatile natural gas prices in this period.

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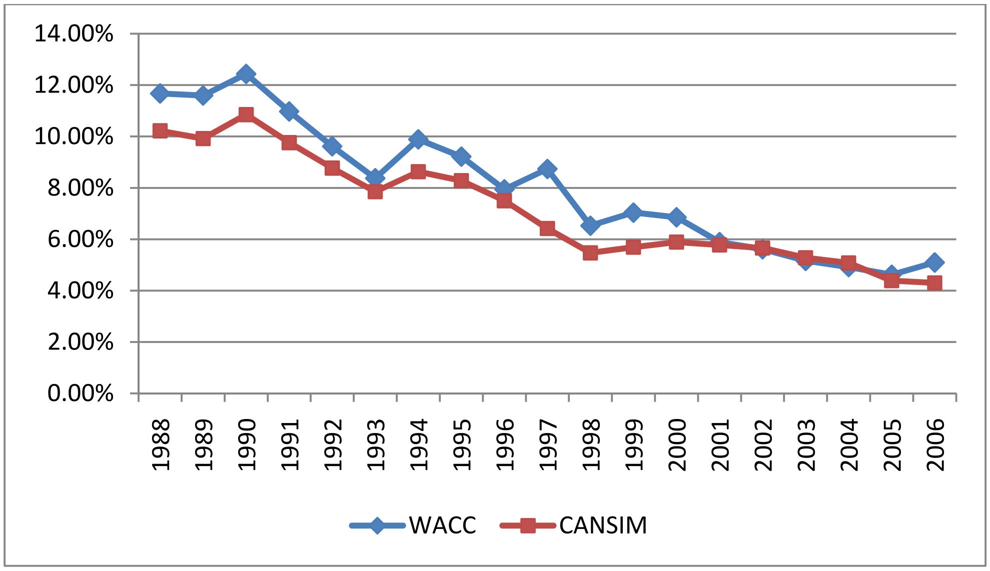
interest rate data available from the financial statements along with the other partial depreciation and tax rate series described in Appendix 4.1. Based on these calculations, also described in Appendix 4.1, the correlation between the resulting user cost of capital series and the long-run interest rate from CANSIM for 1980-2004 was only 0.158.

Figure 4.8: WACC and the CANSIM Interest Rate on Long-Term Bonds (%)



Although the WACC series is not available for the required sample period, which dates back to 1965, in view of this similarity between the WACC series and the long-run interest rate from CANSIM, this latter CANSIM series was used in our subsequent empirical work as a proxy for the price of capital services, although determination of a better user cost of capital series would be a useful subject for future work.

4.3.6 Heat Rates

As described previously, the plant heat rate is a measure of generating station thermal efficiency that is computed by dividing the total BTU content of fuel burned for electric generation by the resulting net generation, so that it reflects the amount of energy required to generate one-kilowatt hour of electricity. Data on the type and quantity of coal and the quantity of natural gas used in generating electricity were obtained from Electric Power Statistics *EPS*, and these data were used to compute heat rates as follows. The data on bituminous Canadian coal and sub-bituminous coal were available in units of short tons from 1965 – 1979, and in units of metric tons from 1974 – 2004. Data on natural gas were available in units of MCF from 1965 – 1969 and in units of thousand cubic metres from 1974 – 2004. The data on coal quantities were converted to common units of metric tons, using the formula 1 metric ton = 1.1023 short tons, while data on natural gas quantities were converted to units of thousand cubic metres, using the formula 1 MCF = 28.317 cubic metres. These data conversions were required only from 1965 – 1973 for both coal and natural gas, since from 1974 onwards the data were already expressed in the desired units of metric tons for coal and cubic metres for natural gas.

Data on the heat content of both kinds of coal as well as for natural gas are available in units of BTU/pound and BTU/ standard cubic foot[21] from 1965 – 1979, respectively, and in units of KJ/kg and KJ/ cubic metres, respectively, from 1974 – 2004. These data on heat content were converted to units of GJ/ metric ton for coal and to units of GJ/ thousand cubic metres for natural gas. The conversion factors used for these calculations are as follows:

1 cubic metre = 35.3147 cubic feet
1000 kg = 2204.623 pounds
1 metric ton = 1000 kg
1 BTU = 1.055056 kJ
1 GJ = 947817 BTU

Given the data on heat content per unit for both kinds of coal and for natural gas in units of GJ/metric ton and GJ/ thousand cubic metres, respectively, as well as the quantity data for both kinds of coal and for natural gas in units of metric tons and thousand cubic metres, respectively, the total heat content for each fuel was computed in units of GJ. Using these data on total heat content of coal (in total) and of natural gas, and the respective amounts of coal- and natural gas- based electricity that was generated, the heat rates for coal- and natural gas-based generation were computed in units of GJ/ GWh.

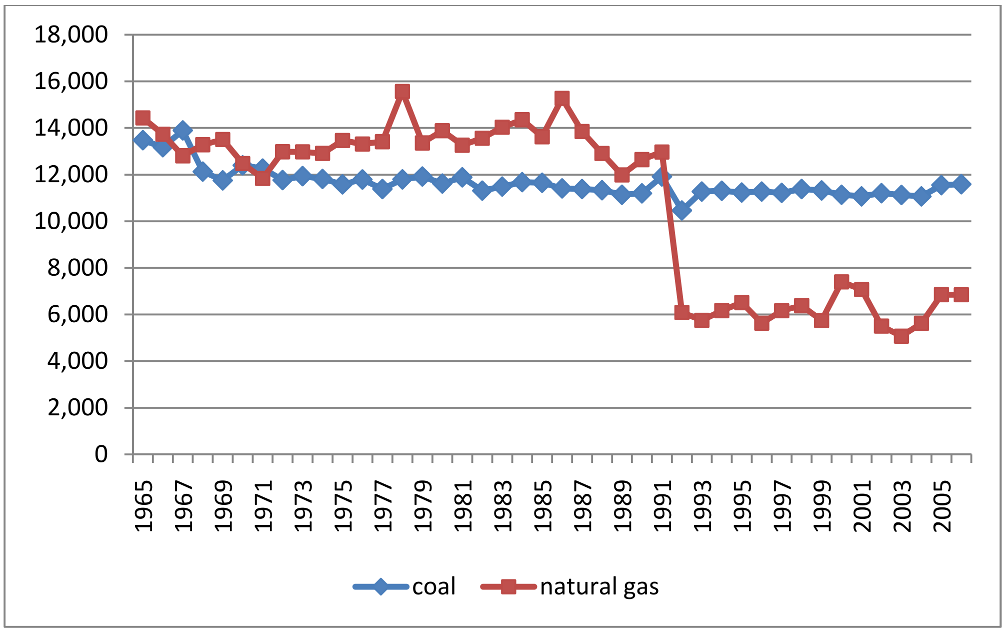
The values of natural gas- and coal-based heat rates that are mentioned in the literature on the Alberta electricity market restructuring are expressed in units of GJ / MWh. According to an Independent Power Producers Society of Alberta *IPPSA* Report entitled "Restructuring's 10 Year progress",[22] the heat rate of a natural gas-based plant – CloverBar – in 1995 was 14 GJ / MWh, while the heat rate of a cogeneration plant in 2005 was 6 GJ/ MWh. The same report also indicates that the market heat rate – defined as the ratio of the market electricity price to the natural gas price – for 2005 is 7.5 GJ / MWh. According to a report by EPCOR on "Clean Coal Symposium",[23] depending on the type of coal plant, coal-based heat rates could range from 8.5 – 10 GJ/ MWh for 2005.

The natural gas-based heat rates computed from the data we have assembled, converted to GJ/MWh, are 6.51 GJ/ MWh for 1995 5.62 GJ/ MWh for 2005, whereas the coal-based heat rate for 2005 is 11.55 GJ/ MWh, which is

[21] 1 standard cubic foot = .02685 cubic metres, compared to 1 cubic foot = 0.0283 cubic metres.
[22] http://www.ippsa.com/pdfs/prestoGovt_2005.pdf , p. 4, 5
[23] Topping (2005), http://www.epcor.ca/SiteCollectionDocuments/Corporate/pdfs/Speeches%20and%20Presentations/cleancoal05.pdf , p. 15.

roughly similar to the values suggested in the literature.[24] Figure 4.9 shows natural gas- and coal-based heat rates from 1965 to 2006. This indicates that while coal-based heat rates have remained relatively constant, natural gas-based heat rates dropped dramatically after 1991, suggesting that the trend to increased efficiency of natural gas-based plants originated prior to, and therefore may have provided impetus to, restructuring. This drastic drop in natural gas-based heat rates by around 53%, from 12,969 GJ/GWh to 6,085 GJ/GWh, from 1991-1992 corresponds to the increase in natural gas based generation of 234% from 2,247 GWh to 7,492 GWh, illustrated in Figure 4.2, and to the increase in natural gas-based capacity of 65% from 1,168 MW to 1,932 MW, illustrated in Figure 4.1. While natural gas-based consumption for electricity generation increased by 56% from 1991 to 1992, the much larger 234% increase in natural gas-based generation explains the drastic fall in natural gas based heat rates.

Figure 4.9: Natural Gas-Based and Coal-Based Plant Heat Rates (GJ/GWh)[25]



[24] Although not used in our analysis, as our objective is a measure of the actual efficiency of the generation plants as opposed to a measure of the efficiency at which they should run, the natural gas-based market heat rate of 7.5 GJ / MWh for 2005 that appears in the literature is only half as much as the 15 GJ/MWh value that we compute from the EPS data set by dividing the market electricity price by the natural gas price.

[25] The natural gas-based and coal-based heat rates were computed by dividing the heat content of the respective fuels consumed for electricity generation by the electricity generation based on the respective fuels. The data used were not plant-specific but rather were overall data from the EPS periodicals. Given this information, it might be reasonable to refer to the computed heat rates as overall heat rates as opposed to aggregate heat rates, as the latter would require data based on individual power plants.

It was noted in Chapter 3, Section 3.6.2, that apart from affecting debt-to-equity ratios, restructuring expectations may also impact capacity investments. Specifically, according to Green (2006), utilities anticipating competition have an incentive to invest in capacity expansions. Therefore, to the extent that natural gas-based plants can be built relatively quickly and cheaply compared to coal-based plants,[26] it is also possible that that this drop in natural gas-based heat rates could be due to restructuring expectations as opposed to technological trends. However, given the fact that retail electricity market restructuring was instituted in 2001, although wholesale restructuring of the Alberta market was instituted in 1996, it is not clear whether this change in 1992 could be attributed to restructuring expectations, especially if it takes only around two years to build a gas based power plant.

Finally, taken together, Figures 4.1, 4.6, 4.8 and 4.9 suggest that while natural gas prices had become more volatile, the increased efficiency in natural gas-based plants as well as lower capital costs are likely to have been major contributing factors to the observed increase in natural gas-based generation capacity.

4.3.7 Heating Degree Days (HDD)

Daily HDD are calculated as the difference between 18C and the average daily temperature when it is below 18C. Monthly HDD are the sum of the daily HDD; annual HDD are obtained analogously. Two sets of HDD data figures were available, one of which is based on weather conditions at different weather stations in Alberta, weighted by population shares. These are therefore slightly different to the quarterly numbers which can be found in "*Quarterly Report of Energy Supply and Demand in Canada*" (QRESD) and later "*Report on Energy Supply and Demand in Canada*" (RESD) from 2002. The QRESD/RESD figures are available on a quarterly basis from 1976-2003, whereas the other set of HDD figures are available on an annual basis from 1961 onwards. While the two sets of figures are different, they have a strong correlation of 0.967 from 1976-2001, so that it does not appear to be overly important as to which series is used here. We use the data series that is available back to 1961. The complete 1965-2006 HDD series, illustrated in Figure 4.10 below, indicates that while HDD peaked in 1996, since then they hovered between 5000 and 5600 degree days, so on this basis there has been no unusually high electricity demand for space heating in the post-restructuring period.[27]

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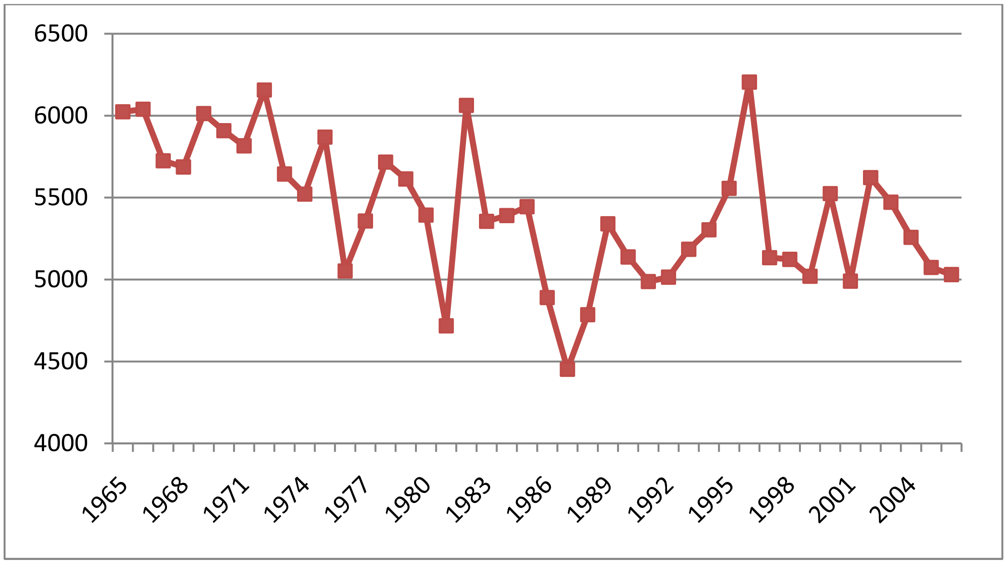
[26] According to the International Energy Agency (2010), coal based plants have a construction time of around four years; whereas the expenditures of constructing gas based plants can be spread over two to three years, http://www.iea.org/Textbase/npsum/ElecCost2010SUM.pdf (last accessed: August, 2011).
[27] We focus here on HDD rather than CDD (cooling degree days) since these are relatively low in Alberta, so that there is relatively low demand for electricity for space cooling purposes in the residential sector.

Figure 4.10: Heating Degree Days



4.3.8 Demand Factors

In modelling the electricity price, it may also be important to control for high electricity demand, or growth in electricity demand, because of the likely effect this will have on the electricity price due to capacity constraints. Economic growth could be used to capture this effect, although it may be partially captured already through the capacity utilization variable.

Direct data on electricity demand by the residential, commercial and industrial sectors are available since 1949 from EPS. However, from 1980 onwards the classifications of the various categories of demand – residential, commercial and industrial – change. Moreover, residential demand from 1949 – 1978 is an aggregate of domestic and agricultural demand. Aside from these aggregation issues, "residential" electricity demand could be used to capture the effect of rising residential demand on electricity prices.[28] However, given that total electricity demand equals total supply, and that average electricity prices are computed as total revenue received / total energy sold, the previously outlined critique of not using data that are defined in terms of units of electricity production (per MWh) would apply here. This is because we are trying to explain electricity prices and if one of the determinants (explanatory variables) is actually used to compute the electricity prices that the model is trying to explain, this would raise the likelihood of an endogeneity issue with the explanatory variables included in the model. Due to these data issues, aggregate economic growth in

[28] However, prices are likely to be affected by total demand, including for the commercial and industrial sectors, and in Alberta industrial demand for electricity is very large.

Alberta is considered as an alternative variable to reflect changes in electricity demand.

Rather than growth in nominal GDP, it is likely to be more appropriate to use growth in real GDP as a variable to reflect demand pressures. Growth in nominal GDP includes growth in demand as well as in prices, so that increases in this variable do not just reflect demand pressures that would be expected to affect the electricity price. For example, if real GDP is actually falling but inflation is rising, then nominal GDP could also be rising even though demand pressures on electricity would be falling. To avoid this issue, growth in real GDP will be used as an explanatory variable in the electricity price equation.

In terms of data on GDP for Alberta, CANSIM contains data in both nominal and real terms. Series V508957 provides annual data on nominal GDP for Alberta from 1961 to 1991, while series V687287 provides nominal GDP from 1981onwards.[29] While data for the overlap period from 1981 to 1991 does not match for the two series, the ratio of V687287 and V508957 for each year of the overlapping time period varies between 0.968 and 0.978, with an average of 0.974. This average value was used to link the values for the earlier period to obtain a continuous series extending from 1961 onwards. The series V3839826, which contains the Implicit Price Index for GDP for 1981-2004 with 1997 as the base year, was also extracted and used in conjunction with the linked series V687287 to compute real GDP for 1981-2004. As an alternative, the series V3840301, which contains GDP figures from 1981 - 2004 at constant 1997 prices, was extracted from CANSIM. While the two sets of real GDP differ, they exhibit a strong correlation of 0.987.

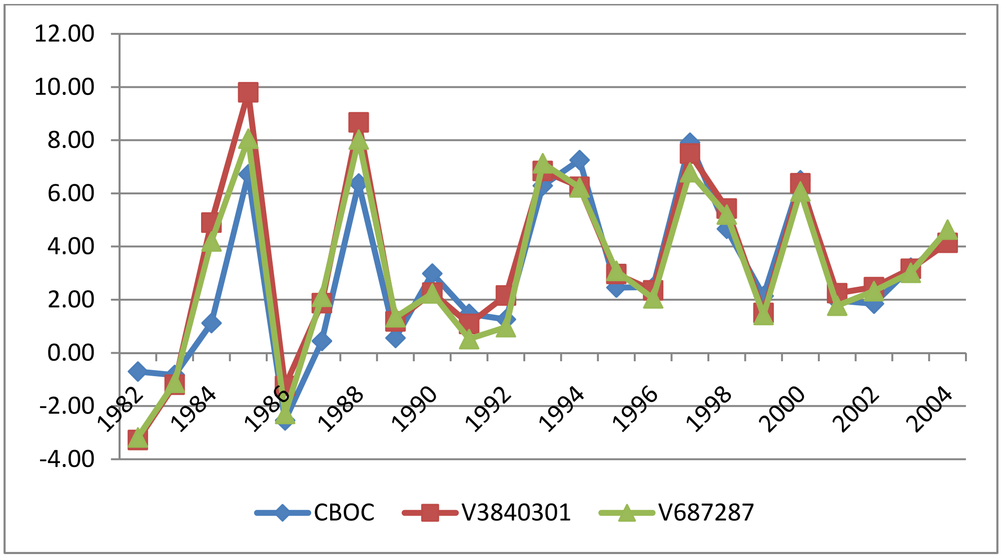
However, neither set of real GDP data – Series V3840301 or the series computed from V687287 as described above – are available prior to 1981, so that annual growth rates in real GDP for Alberta prior to 1982 cannot be computed. An alternative data source that includes information for this earlier period is the Conference Board of Canada (*CBOC*), which provides (among other data series) quarterly information on real GDP for Alberta from 1961 onwards. In view of its availability for the period that we require, annual growth in real GDP for Alberta computed from this series is used in our subsequent empirical work. Although the real GDP data series obtained from CBOC and the two CANSIM series described above are not exactly the same, for the 1981 to 2004 period, the correlations between the real GDP CBOC series and CANISM Series V3840301 and the series based on V687287 (and V3839826) for 1981 to 2004 are 0.9965 and 0.9976, respectively. The correlations between annual growth in real GDP calculated using these two CANSIM-based series and calculated using average annual real GDP values from the CBOC series, are 0.908 and 0.928, respectively.

Figure 4.11 shows that the annual growth rates in real GDP for Alberta computed from the CANSIM series and also from the CBOC data are very

[29] The same information is provided by Series V687647.

similar. In contrast to the picture painted by the HDD values in Figure 4.10, the information in Figure 4.11 suggests growing electricity demand in the post-restructuring period based on increasing real GDP growth after 2001.

Figure 4.11: Growth Rate in Real GDP for Alberta (%)



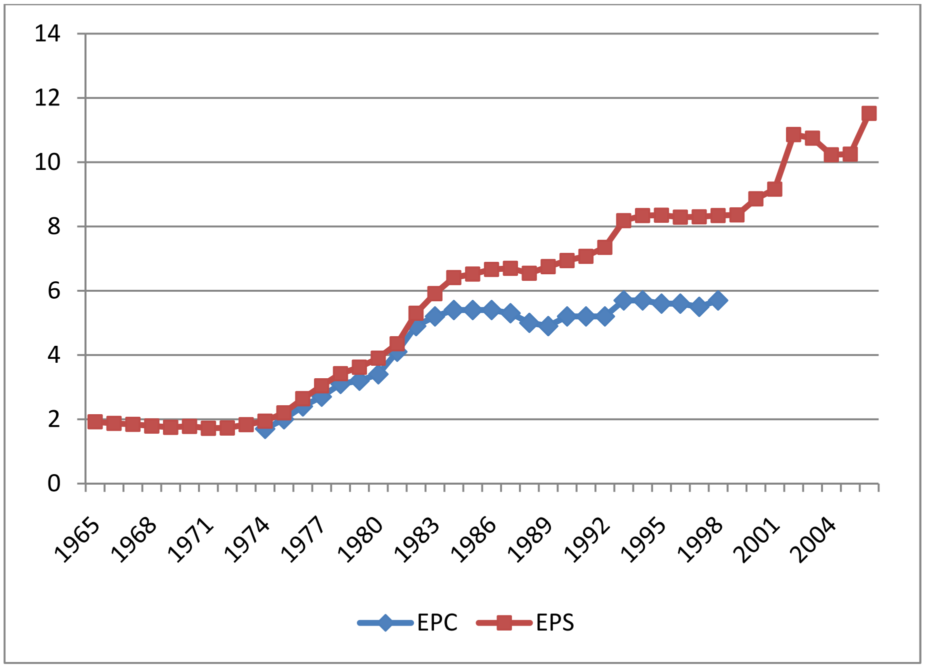
CBOC growth rates computed from average real GDP

4.3.9 Electricity Price

In addition to the per-unit prices for major inputs, data are also required on the dependent variable, namely the electricity price. *Electric Power Statistics* (EPS) and *Electric Power in Canada* (EPC) both provide average revenue in units of $/kWh for 1965-2006 and 1974-1998, respectively. For the data from EPS, average revenue is calculated as the ratio of Revenue received to Energy sold, which is the electricity price measured in cents/KWh.[30] The two series, displayed in Figure 4.12, are similar from 1974 to about 1983, after which time the EPS-based prices are increasingly higher than the corresponding EPC values. While the EPS price series grows reasonably steadily until 1993, and then levels off until 1999, the EPC price series levels off from about 1983. Nevertheless, the two series have a correlation of 0.96 for the 1974-1998 period. Interestingly, however, the EPS series does not appear to reflect the price spike observed in 2001, peaking instead in 2002.

[30] The EPS data refers to revenue received and energy sold by electric utilities and industrial establishments in conjunction with domestic and farm businesses.

Figure 4.12: Alberta Electricity Prices (c/kWh)



There are a variety of other sources available for Alberta electricity prices, although none appear preferable to the EPS series. Hydro Quebec produces annual compilations of average electricity prices for Edmonton (as well as other Canadian cities), both including and excluding taxes for four main usage categories: residential, small power, medium power, and large power.[31] However, for each category there are subdivisions based on voltage, load factor and consumption level, so that it would be difficult to determine a single or average price for some categories. Of more concern, however, is the fact that these data begin only in 1993 and are specific to Edmonton. Electricity prices are also available in the *Energy Use Data Handbook Tables* available from the Office of Energy Efficiency at Natural Resources Canada, but only since 1990.[32] The Consumer Price Index (CPI) for electricity could also be used, but although it is available for Alberta prior to 1992, since then it has been calculated separately for Edmonton and Calgary and would therefore need to be aggregated, necessitating additional assumptions. Also, since 1995, this index refers to water, fuel and electricity as opposed to just electricity.[33] Finally, since the Electric Power Selling Price index (EPSI)[34] is reported for non-residential customers, it is not appropriate for use in the context of the residential sector.

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[31] Hydro Quebec, (1993-2004), "Comparisons of Electricity Prices in Major North American Cities"

[32] Natural Resources of Canada, Office of Energy Efficiency,
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tableshandbook2/res_00_18_e_4.cfm?attr=0

[33] See Statistics Canada, (1982-2003), "Consumer Prices and Price Indexes"

[34] Statistics Canada, "Industry Price Indexes"

Although electricity rates in Alberta today are a function of Alberta Power Pool prices,[35] these are wholesale rather than retail prices, and only became available in 1997 with the beginning of the restructuring of the electricity industry in Alberta. For years prior to 1997, which is the focus of our pre-restructuring estimation, it would be necessary to use a different series. If our objective ultimately were to see how the model forecasts in the post-restructuring environment (as opposed to obtaining counterfactual prices) then it might be useful to use the Pool prices. However, the correlation between the Pool prices and EPS electricity prices for the period 1997 to 2004, of 0.09, is very low.

In summary, given the issues with the alternate price series, and despite its inclusion of sales for farm business use as well as for domestic use prior to 1981, in view of its availability for the pre-restructuring period, the EPS electricity price series is used in the estimation that follows.[36]

4.4 Results

4.4.1. Model Specification

Based on the model development described in Section 4.2, and the data and variables described in Section 4.3, and assuming initially a linear specification, the structural model of electricity prices (4.4) that is to be estimated has the following form:

$$P_t = \beta_1 + \beta_2 cc_t + \beta_3 gc_t + \beta_4 cp_t + \beta_5 gp_t + \beta_6 cu_t + \beta_7 gu_t + \beta_8 ch_t + \beta_9 gh_t + \beta_{10} cs_t + \beta_{11} cscp_t + \beta_{12} hdd_t + \beta_{13} gr_t + \beta_{14} w_t + \beta_{15} r_t + \varepsilon_t \quad (4.6)$$

where:

P_t is the price of residential electricity (cents/kWh),

cc_t is coal capacity (MW),

gc_t is natural gas capacity (MW),

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[35] These prices are available from Alberta Electric System Operator, http://www.aeso.ca. Another issue to note is that these are prices based on marginal costs of generation, whereas regulated prices were based on average costs of generation.

[36] The electricity price that consumers face has many components. These include the energy charge (generation), but also transmission and distribution charges (which are still regulated in Alberta) as well as various municipal franchise fees and other charges, including various rate riders. Municipal franchise fees and some of these other charges may change over time in ways that have nothing to do with restructuring, although it may be easier for municipal franchise fees to be changed in a restructured (non-regulated) environment. In any event, at the aggregate (residential Alberta) level the separate effects of these various components cannot be taken into account. We focus on the aggregate residential electricity price because data for this price are available and because consumers cannot arbitrarily choose to pay only some components of the price.

cp_t is the price of coal ($/GJ),

gp_t is the price of natural gas ($/GJ),

cu_t is coal utilization (%),

gu_t is natural gas utilization (%),

ch_t is the average heat rate of coal (GJ/gWh), [37]

gh_t is the average heat rate of natural gas (GJ/gWh),

cs_t is the share of coal in generation (proportion),

$cscp_t = cs_t \times cp_t$ is the product of the share of coal in generation and the price of coal,

hdd_t is heating degree days,

gr_t is the rate of growth in real GDP (%),

w_t is the wage rate (thousand $/worker),

r_t is the long-run interest rate (%), and

ε_t is a random error term.

Compared to the model specification in (4.4), the only additions in (4.6) are the share of coal in generation, $\mathrm{cs_t}$, and its interaction with the coal price. The share is included to allow for the possibility that, given different fuel prices, the electricity price may depend on to the relative shares of the two main fuels, while the interaction term allows for the possibility that the impact on the electricity price of increased fuel prices may depend on the share of those fuels in generation. Note that although the sum of the coal share and the natural gas share of generation is not equal to one, it is quite close so that inclusion of both shares led to problems with multicollinearity. In addition, the model is estimated using annual data for the pre-restructuring period, which is initially taken to be 1965 to 1997 (33 observations), and there are already 15 parameters in (4.6).

4.4.2. Initial Results

OLS estimation results obtained when the structural model of residential electricity prices in Alberta, (4.6), is estimated for the period 1965 to 1997 using annual data, are presented in Column (1) of Table 4.1. There is evidence of first-order autocorrelation (but not of autocorrelation of any higher order), and this is alternately dealt with using standard errors based on an autocorrelation-consistent

[37] The natural gas-based and coal-based heat rates were computed by dividing the heat content of the respective fuels consumed for electricity generation by the electricity generation based on the respective fuels. The data used were not plant specific but rather overall data from the EPS periodicals. Given this information, it might be reasonable to refer to the computed heat rates as average heat rates as opposed to marginal heat rates as the latter would require data based on individual power plants.

covariance matrix estimator (as in Column (1)),[38] or by estimating a first-order autoregressive (AR(1)) model, as reported in Column (2) of Table 4.1. The estimated autoregressive parameter in this latter case is 0.49, and is significantly different from both one and zero. Despite this finding, the high R-squared value and evidence of autocorrelation, suggests that at least some of the variables may be non-stationary, which we consider later.[39] A RESET test revealed no evidence of omitted variables or functional misspecification, there is also no evidence of heteroskedasticity, and a Box-Cox test did not reject the use of the linear functional form. Generally, the results in Columns (1) and (2) are consistent with each other in terms of signs, significance and even magnitude, and as Figure 4.13 shows, the fitted values from both estimated models track the actual electricity price series very closely. In view of this finding, in the ensuing analysis we focus on the OLS results in Column (1) with the autocorrelation-corrected standard errors. Possible modifications to the model specification and estimation are considered later.

The main purpose of our model is to forecast electricity prices in the post-restructuring period and to compare these with the prices that were actually observed in this period in order to assess whether there is any evidence that restructuring caused prices to be higher than they would have been in the absence of the restructuring. For this purpose, annual predictions were made for the period 1998-2005 based on the parameters of the model estimated using data from 1965-1997 and using observed values of the explanatory variables in for years following the estimation period. Our principal finding, as shown in Figure 4.14, is that the predicted prices exceed the actual prices for the years 1998-2005. Thus, these initial results suggests that actual electricity prices in the post-restructuring period were lower than those that would have been experienced if restructuring had not occurred and the same model of electricity price determination continued to apply.

Since restructuring at the retail level in Alberta did not begin until 2001, the model can be re-estimated using alternative definitions of the pre-restructuring period, specifically (i) from 1965-1998, (ii) from 1965-1999, and (iii) from 1965-2000. The model in (4.6) was re-estimated based on each of these alternative definitions of the pre-restructuring period, and again predictions were made in each case for electricity prices in subsequent years. Estimated parameters for (iii) are included in Column (3) of Table 4.1 As shown in Figure 4.14, the result concerning the relationship between the counterfactual (predicted) prices and the actual prices in the post-restructuring period changes somewhat when the model is estimated using these slightly different pre-restructuring sample periods. This indicates that the results are sensitive to the estimation period. Since retail prices

[38] Here the order of the autocorrelation-consistent covariance matrix estimator that is used is 2, although the results were not materially affected with different choices.

[39] Non-stationarity may also be a cause of the unexpected signs for the estimated coefficient on coal capacity, heat rates, the natural gas based utilization ratio (since we expect prices to go up if scarcity – as reflected by utilization – increases) and the interest rate.

remained regulated until the beginning of 2001, in terms of evaluating the effect of restructuring, the main focus is on 2001, the year that retail restructuring took effect, and the ensuing year. On this basis of the model estimated from 1965–2000, it appears that retail prices did increase as a result of restructuring, although this increase appears to have been reversed in 2005.

TABLE 4.1: Pre-Restructuring Period Estimation Results

Variable	1965-1997		1965-2000
	(1)	(2)	(3)
coal capacity (cc_t)	0.0009** (0.0001)	0.0009** (0.0002)	0.0009** (0.0001)
nat. gas capacity (gc_t)	0.0004 (0.0004)	0.0004 (0.0004)	-0.0002 (0.0003)
coal price (cp_t)	-4.5603 (6.0030)	-2.5884 (7.15)	3.4960 (4.6310)
nat. gas price (gp_t)	0.6698** (0.1851)	0.6300** (0.1614)	0.4011* (0.1647)
coal utilization ratio (cu_t)	0.0107 (0.0058)	0.0115† (0.0056)	0.0097† (0.0056)
nat. gas utilization ratio (gu_t)	-0.0168 (0.0111)	-0.0116 (0.0102)	-0.0229* (0.0092)
heat rate of coal (ch_t)	-0.00001 (0.00004)	-0.00002 (0.00005)	-0.00001 (0.0002)
heat rate of nat. gas (gh_t)	-0.0001 (0.0001)	-0.00002 (0.0001)	-0.0001* (0.00004)
coal share of generation (cs_t)	-3.8782** (1.0450)	-3.0128* (1.271)	-2.1771 (1.3280)
coal price * share coal ($cscp_t$)	10.024 (6.4270)	7.7587 (7.799)	2.4473 (5.1660)
heating degree days (hdd_t)	-0.00003 (0.0001)	0.00002 (0.0001)	0.0001 (0.0001)
growth (gr_t)	-0.0082 (0.0105)	-0.0145 (0.0114)	-0.0082 (0.0124)
wage rate (w_t)	0.0018 (0.0113)	-0.0039 (0.0145)	-0.0144 (0.0119)
interest rate (r_t)	-0.1106** (0.0182)	-0.1051** (0.0351)	-0.1170** (0.0197)
constant	4.8903 (2.8130)	3.0846 (2.5580)	4.3359 (3.0820)
R-squared	0.9974	0.9978	0.9969
autocorrelation coefficient (rho)		0.4888** (0.1519)	
number of observations	33	33	36

Notes: 1. **, *, and † indicate significance at the 1%, 5%, and 10% levels, respectively.

2. Numbers in parentheses are estimated standard errors, which in Columns (1) and (3) are based on an autocorrelation consistent (Newey-West) covariance matrix.

Figure 4.13: Actual and Fitted Electricity Prices, 1965-1997

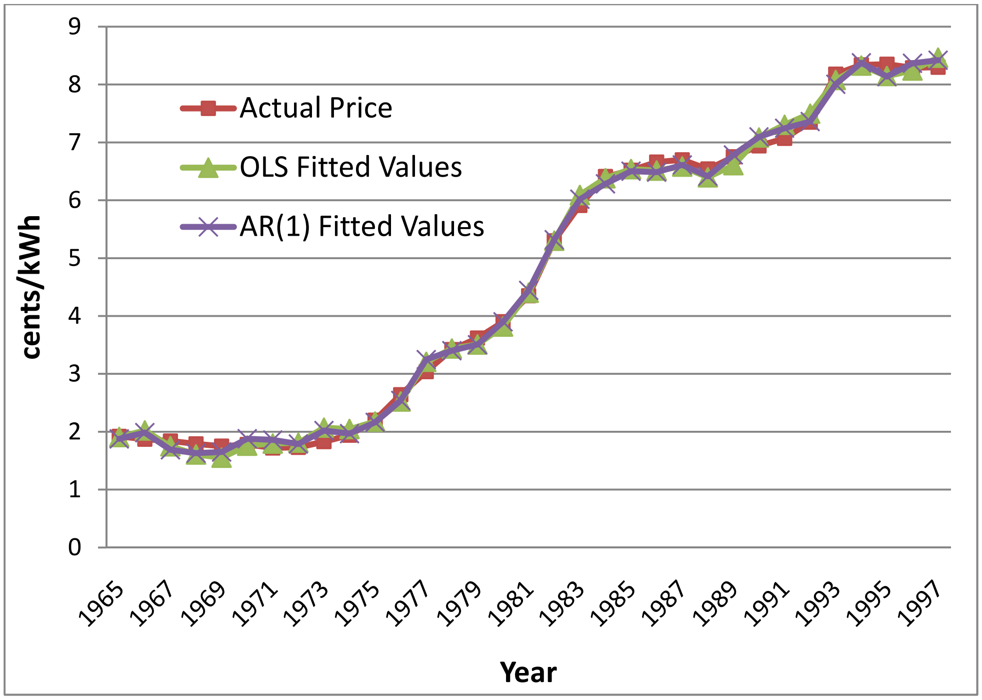
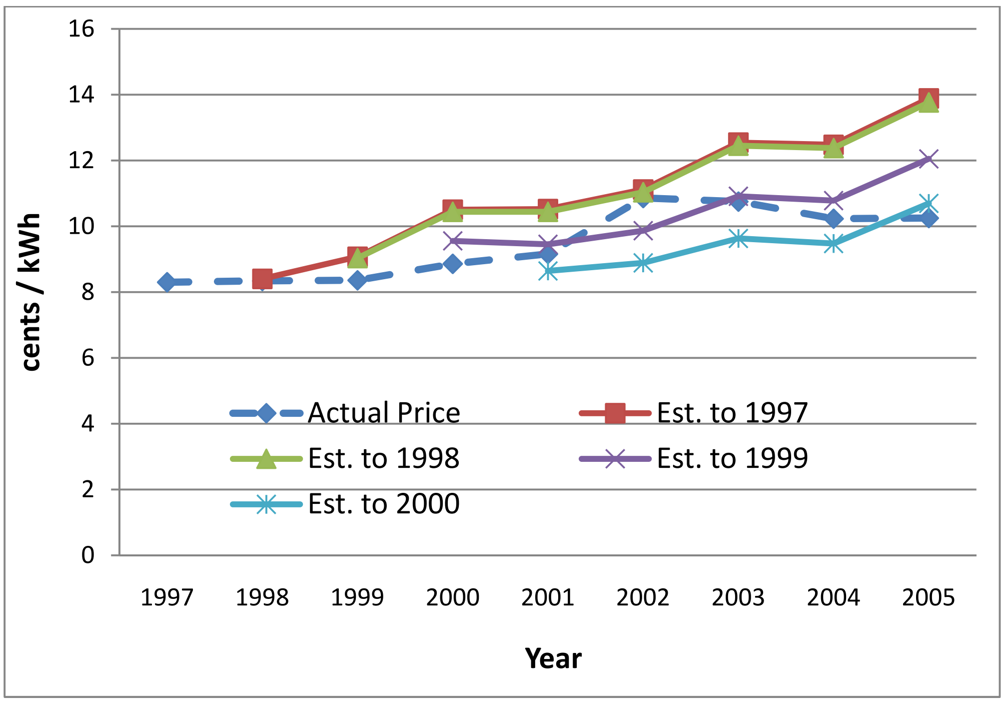
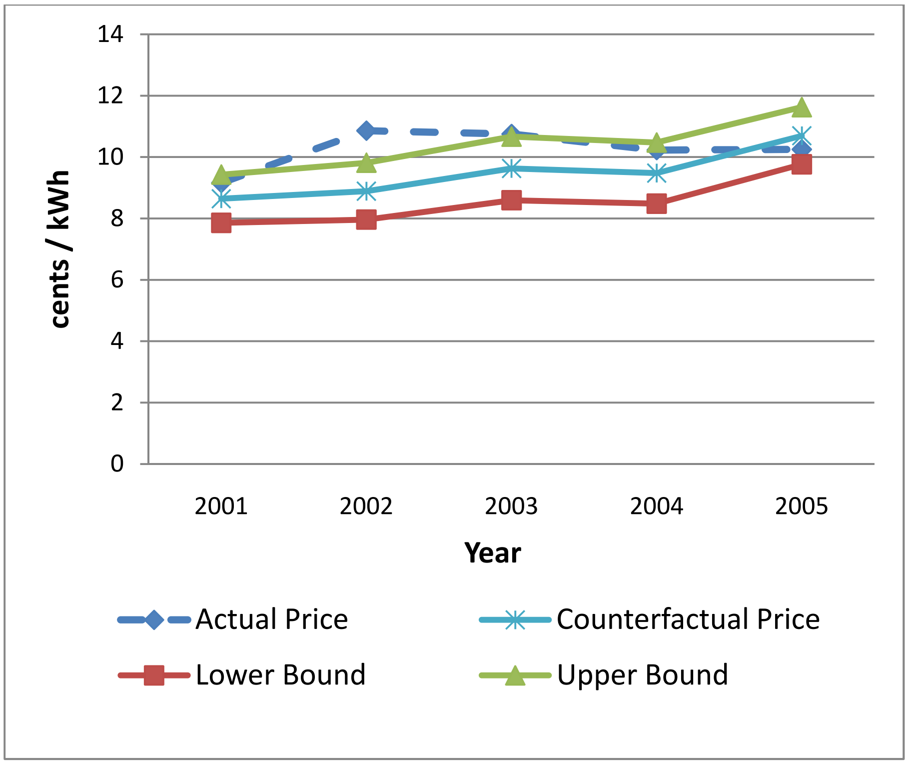


Figure 4.14: Predictions beyond the Estimation Period



Although Figure 4.14 shows the counterfactual prices to be below the actual prices for 2001 to 2004 when the model is estimated for the pre-restructuring period defined as 1965–2000, it is not clear that the two sets of prices are statistically significantly different. To examine this question, 95% confidence bounds were calculated for the forecast prices obtained from this model estimation. These confidence bounds are shown in Figure 4.15, along with the forecasts (the counterfactual prices) and the actual prices. As this figure shows, for 2001, 2004 and 2005, the upper confidence bound exceeds the actual price, but in 2002 and 2003, this is not the case, so that in these two years the counterfactual price is significantly lower than the actual price, using a 5% level of significance. Thus, in these two years, the price with restructuring is significantly higher than the price would have been if restructuring had not occurred. Even in the other years, the lower bound always lies below the actual price, so that based on this analysis, restructuring has not resulted in a retail electricity price that is significantly lower than what would have been experienced had restructuring not occurred.

Figure 4.15: Actual Prices and Confidence Bands for Counterfactual Prices



4.4.3. Sensitivity Analysis

Sensitivity analysis of the model also included allowing for a time trend to control for technological progress and dealing with potential simultaneity bias due to variables like capacity and generation that could proxy for electricity demand.

4.4.3.1 Time Trend

In determining the impact of restructuring on electricity prices, the role of restructuring may be confounded with technological change. Although this has been controlled for to some extent by including heat rates, any additional role of technological change in impacting electricity prices can be allowed for by incorporating a time trend. For example, Arano and Blair (2008) use a time trend to capture the effect of technology in the US context, whereas Vlachou et al. (1996) use a time trend to capture non neutral and scale augmenting technological change in regression analysis.

When (4.6) is re-estimated with a time trend included, the t-ratio is determined to be only –0.4279 based on the estimation method in Column (1) of Table 4.1, and +0.1786 based on the estimation method in Column (2) of Table 4.1. When a squared time trend was also included, both the time trend and the squared time trend were individually insignificant, and the two together were not jointly significant. Therefore, no further analysis was undertaken with the time trends included in the model.

4.4.3.2 Endogeneity

Simultaneity bias may arise when structural models are estimated, as such models generally include both endogenous and predetermined explanatory variables, in contrast to reduced form models that comprise only predetermined variables. Given that a structural model is being employed to estimate the determinants of electricity prices, the issue of simultaneity bias needs to be considered here. As a starting point, the explanatory variables that may be endogenous include those which measure capacity, generation, utilization ratios, and heat rates. Since the post-restructuring period is not included in the sample period that is used for estimation, the issue of restructuring impacting both utilization ratios and heat rates on the one hand and the dependent variable – electricity prices – on the other, does not arise, at least so far as estimation is concerned.[40] Therefore, for the purposes of estimation for the pre-restructuring period, utilization ratios and heat rates will be considered to be exogenous. Rather, the emphasis in this section will be on the simultaneity bias arising from the relationship between electricity price and consumption. In this respect,

[40]Of course the post-restructuring values of these variables may be endogenous in the sense that they are affected by restructuring, so that the values observed for them in the post-restructuring period may not be the values that would have been observed in that period had restructuring not occurred. A method to account for this issue is developed and applied in Chapter 5.

variables measuring generation and capacity will be considered to be potentially endogenous variables since they reflect electricity consumption, which is used to calculate the very electricity price that is being modelled, as explained below. If testing reveals these variables to be endogenous, an instrumental variable estimation approach will be used.

The fact that electricity rate structures often have multiple blocks indicates that average price is a function of the quantity of electricity that is consumed. However, electricity prices also affect the quantity of electricity consumed due to the negative relationship between price and quantity. This illustrates the nature of the simultaneity bias that arises when electricity demand is modelled as a function of the electricity price and vice versa (Berndt, 1991). The simultaneity bias issue is potentially a significant one because while quantity purchased is the most important determinant of electricity price, the electricity price is also a highly significant determinant of electricity consumption. While no electricity consumption variable has been explicitly used in the model, to the extent that capacity and generation variables capture consumption as well, since supply and demand in the electricity market must always match, a potential simultaneous relationship between price and quantity exists and thus a potential need to account for any resulting simultaneity bias.

Electricity prices used in the model are determined by dividing the revenue received by the amount of energy sold by the electricity utilities, and as such electricity prices reflect average as opposed to marginal values, which is noteworthy as the use of average prices also leads to an issue of simultaneity bias in estimating electricity demand equations.[41] To the extent that the use of average prices leads to simultaneity bias in electricity demand estimation, then it is likely that simultaneity bias may also exist in models of the determination of the electricity price, particularly when average electricity prices are used. Thus, given that in Alberta, marginal electricity price data for an extended period such as we use for estimation can only be extracted from consumer bills, and this requires access to residential electricity bills covering the full sample period, which was not feasible, there is little choice but to use the average electricity price in the analysis and to attempt to account for the possibility of endogeneity and resulting simultaneity bias.

In order to test for and, if necessary, ultimately account for the simultaneity bias arising from four variables – coal-based capacity, natural gas-based capacity, the share of coal-based generation, and the product of this share and coal prices – instrumental variables (IVs) are required. Four variables are selected for this purpose: population growth for Alberta (based on CANSIM series V15), the share of exports in GDP for Canada (based on CANSIM series V646954 and V3863688), real indirect taxes on production in Canada (from

[41] Studies conducted in the context of estimating electricity demand often use marginal electricity prices, although not using the average price is also likely to bias the parameter estimates (Berndt, 1991).

CANSIM series V4394635, with V1997756 used as the deflator) and real wages for Canada (based on CANSIM series V348964 (1961-1980) and V691712 (1981-2007), with V1997756 used as the deflator). Data availability precludes the use of Alberta-based figures for the final three variables. Although a specific IV is not uniquely assigned to each of the "problem" variables, since the variables that are being instrumented for – capacity variables and share of generation – have units of MW or percentages, the IVs are selected in units that are consistent with real and percentage units.

All four instrumental variables can be considered to be relevant in the context of the explanatory variables used in the model under consideration, as greater population, exports, taxes on production and wages would be concomitant with increased electricity consumption, capacity and generation. Moreover, none of the four variables appear to have a direct impact on the determination of electricity prices. Thus, all four variables seem to satisfy the two requirements of instrument variables, that is, relevance and exogeneity. However, before any IV estimation is undertaken, endogeneity tests – a Hausman test and a Durbin-Wu-Hausman test – are used in order to ascertain if IV estimation is needed, since OLS would be the efficient estimator otherwise.

In general, the Hausman test determines the significance of the difference between the OLS and IV parameters estimates. As such, it requires estimation of the model by OLS and by IV estimation. The Durbin-Wu-Hausman test is based on regressing each of the potentially endogenous variables on all the exogenous variables in the model, including the instruments, and obtaining either the fitted values or the estimated residuals. These fitted values or estimated residuals are then included as additional variables in the original equation and tested (jointly) for significance. The problem with applying either of these tests in the present context is that the results reported in Table 4.1 indicate evidence of autocorrelation. It is not clear how these endogeneity test procedures can be modified in this case. One possibility is to ignore the autocorrelation, although it is not clear then whether the test result is dependent on this choice. A second is to estimate the models taking account of the autocorrelation (in both estimations with the Hausman test, and in the second step with the Durbin-Wu-Hausman test) but to otherwise proceed with the tests as usual. Here, both of these alternatives are used; the test results – using the longer pre-restructuring sample period from 1965 to 2000 – are provided in Table 4.2.

Table 4.2: Endogeneity Test Results

Endogeneity tests	Estimation Method	Test Type	Statistic	Critical Value
Hausman	OLS/IV	F test (df1=3, df2=18, 5%)	0.36	9.48
Durbin-Wu-Hausman	OLS/OLS	F test (df1=4, df2=17, 5%)	3.89	2.96
Hausman	AR(1)/[IV-AR(1)]	Chi-square (df = 4, 5%)	2.30	9.48
Durbin-Wu-Hausman	OLS/AR(1)	F test (df1=4, df2=17, 5%) Chi-square (df=4, 5%)	6.21 24.85	2.96 9.48

It is clear from Table 4.2 that with or without allowing for autocorrelation, the Hausman test fails to reject the null hypothesis of the absence of endogeneity due to coal-based capacity, natural gas-based capacity, the share of coal-based generation, and this coal share multiplied by the coal price. However, the Dubin-Wu-Hausman test yields the opposite result both with and without allowing for autocorrelation in the second step. While these conflicting test results might suggest that we should err on the side of caution and proceed as though the four explanatory variables are endogenous, the problem with this approach is that the appropriate remedy in this case is to do IV estimation. However, IV estimation has already been done as part of the Hausman test, and according to this test the parameters in the two cases (OLS and IV estimation) are not significantly different. On this basis, there is no point continuing with the analysis using IV estimation. Of course this result may be dependent to some extent on the instruments that have been chosen, with a different set of instruments possibly yielding different results. This remains as a potential area for future research.

4.4.4. Non Stationarity

As noted earlier, there is a potential problem with many of the variables in the analysis possibly being non-stationary. If this is the case, OLS applied to the levels variables may lead to a problem with spurious regressions. To examine this possibility, tests of non-stationarity were run on each of the variables. These tests and the results obtained are described in Section 4.4.4.1. Estimation and determination of counterfactual electricity prices that takes account of the findings concerning non-stationarity are presented in Section 4.4.4.2.

4.4.4.1 Tests of Non Stationarity

Tests of non-stationarity have notoriously poor power in small samples, such as the case here where only 33 observations are used in the estimation (1965 to 1997, inclusive), so that the results of these tests cannot be viewed as definitive. Nevertheless, Augmented Dickey-Fuller (ADF) and Phillips Perron (PP) tests as well as KPSS tests were conducted (using data for the entire sample from 1965 to 2005) to detect the existence of unit roots by following the strategy adopted by Elder and Kennedy (2001).

According to Elder and Kennedy (2001), the variables must first be visually inspected to discern whether the variables are growing or not, and based on the inspection results, the ADF test can be conducted by including a time trend in the case the variable exhibits growth and without a time trend in the absence of growth in the variable series. In the context of the ADF test with the time trend, rejection of the null implies a trend stationary series whereas the non-rejection of the null leads to confirmation of a unit root. On the other hand when the ADF test is conducted without the time trend, the rejection of the null implies drift in the series whereas the non-rejection of the null leads to a unit root as before. This strategy allows one to avoid double and triple differencing of economic series as well as allows one to carefully distinguish between trend and difference stationary series.

Based on visual inspection of the graphs of the 15 variable series, six series exhibited a growth trend, so that when the unit root tests were conducted in EVIEWS for these 6 series – electricity price, coal and natural gas based capacity, coal and natural gas prices, and annual wages per worker – a time trend was included. Unit root tests were conducted on the other 9 series without a time trend but with a drift term. Test statistics and the critical values are reported for all three unit roots tests for each of the 15 variables in Tables 4.3 to 4.5 below. A summary of the results based on the test statistics in these three tables above is provided in Table 4.6.

While the ADF and PP test results more or less confirmed the findings from the visual inspection of the graphs of the 15 variables, the KPSS test on occasions yielded contrary results. Both the ADF and PP tests indicate that all variables except growth, heating degree days and coal-based heat rates are non-stationary. To estimate the model in this case, all the variables except these and the interest rate[42] would need to be first differenced and the model re-estimated.[43]

[42] The interest rate was found to be non-stationary by both the ADF and the PP tests, however it was not first differenced on the basis of the graph of the interest rate which suggests that it is a stationary series.

[43] The series were not found to be cointegrated, so that an Error-Correction Model could not be estimated.

Table 4.3: Augmented Dickey-Fuller (ADF) Unit Root Tests

Variable	Levels tests					1st Difference tests				
	Test type	t statistic	Critical Values			Test type	t statistic	Critical Values		
			1%	5%	10%			1%	5%	10%
Electricity Price	trend + drift	-2.49	-4.21	-3.53	-3.19	drift	-4.71	-3.61	-2.94	-2.61
Coal basedCapacity	trend + drift	-0.02	-4.21	-3.53	-3.19	drift	-5.6	-3.61	-2.94	-2.61
Gas based Capacity	trend + drift	-0.91	-4.21	-3.53	-3.19	drift	-3.57	-3.61	-2.94	-2.61
Coal price	trend + drift	-2.17	-4.21	-3.53	-3.19	drift	-7.68	-3.61	-2.94	-2.61
Gas price	trend + drift	0.28	-4.21	-3.53	-3.19	drift	-5.43	-3.61	-2.94	-2.61
Coal based utilization ratio	drift	-1.07	-3.61	-2.94	-2.61	none	-11.8	-2.62	-1.95	-1.61
Gas based utilization ratio	drift	-1.65	-3.61	-2.94	-2.61	none	-6.56	-2.62	-1.95	-1.61
HDD	drift	-4.11	-3.61	-2.94	-2.61					
Economic Growth	drift	-4.46	-3.61	-2.94	-2.61					
Wages	trend + drift	-3.16	-4.21	-3.53	-3.19	drift	-6.5	-3.61	-2.94	-2.61
Gas based heat rates	drift	-1.17	-3.61	-2.94	-2.61	none	-6.85	-2.62	-1.95	-1.61
Coal based heat rates	drift	-6.2	-3.61	-2.94	-2.61					
Interest rates	drift	-1.07	-3.61	-2.94	-2.61	none	-4.81	-2.62	-1.95	-1.61
share of coal generation	drift	-2.39	-3.61	-2.94	-2.61	none	-5.84	-2.62	-1.95	-1.61
coal price * share of coal generation	drift	-1.09	-3.61	-2.94	-2.61	none	-6.57	-2.62	-1.95	-1.61

Note: The Null Hypothesis for the ADF test is non-stationarity, which is only rejected if the test statistic is less than the critical value.

Table 4.4: Phillips-Perron (PP) Unit Root Tests

Variables	Levels tests					1st Difference tests				
	Test type	t statistic	Critical Values			Test type	t statistic	Critical Values		
			1%	5%	10%			1%	5%	10%
Electricity Price	trend + drift	-2.63	-4.21	-3.53	-3.19	drift	-4.61	-3.61	-2.94	-2.61
Coal based Capacity	trend + drift	0.05	-4.21	-3.53	-3.19	drift	-5.7	-3.61	-2.94	-2.61
Gas based Capacity	trend + drift	0.1	-4.21	-3.53	-3.19	drift	-3.61	-3.61	-2.94	-2.61
Coal price	trend + drift	-2.33	-4.21	-3.53	-3.19	drift	-7.55	-3.61	-2.94	-2.61
Gas price	trend + drift	0.63	-4.21	-3.53	-3.19	drift	-5.62	-3.61	-2.94	-2.61
Coal based utilization ratio	drift	-2.23	-3.61	-2.94	-2.61	none	-13.17	-2.62	-1.95	-1.61
Gas based utilization ratio	drift	-1.65	-3.61	-2.94	-2.61	none	-6.56	-2.62	-1.95	-1.61
HDD	drift	-4.04	-3.61	-2.94	-2.61					
Economic Growth	drift	-4.48	-3.61	-2.94	-2.61					
Wages	trend + drift	-2.98	-4.21	-3.53	-3.19	drift	-7.84	-3.61	-2.94	-2.61
Gas based heat rates	drift	-1.04	-3.61	-2.94	-2.61	none	-6.92	-2.62	-1.95	-1.61
Coal based heat rates	drift	-3.7	-3.61	-2.94	-2.61					
Interest rates	drift	-1.24	-3.61	-2.94	-2.61	none	-4.76	-2.62	-1.95	-1.61
share of coal generation	drift	-2.29	-3.61	-2.94	-2.61	none	-6.03	-2.62	-1.95	-1.61
coal price * share of coal generation	drift	-1.09	-3.61	-2.94	-2.61	none	-6.71	-2.62	-1.95	-1.61

Note: The Null Hypothesis for the PP test is non-stationarity, which is only rejected if the test statistic is less than the critical value.

Table 4.5: KPSS Unit Root Tests

Variables	Levels tests					1st difference tests				
	Test type	LM test statistic	Critical Values			Test type	LM test statistic	Critical Values		
			1%	5%	10%			1%	5%	10%
Electricity Price	trend + drift	0.083	0.22	0.15	0.12					
Coal based Capacity	trend + drift	0.18	0.22	0.15	0.12	drift	0.4	0.74	0.46	0.35
Gas based Capacity	trend + drift	0.18	0.22	0.15	0.12	drift	0.38	0.74	0.46	0.35
Coal price	trend + drift	0.12	0.22	0.15	0.12	drift	0.08	0.74	0.46	0.35
Gas price	trend + drift	0.133	0.22	0.15	0.12	drift	0.43	0.74	0.46	0.35
Coal based utilization ratio	drift	0.7	0.74	0.46	0.35	drift	0.12	0.74	0.46	0.35
Gas based utilization ratio	drift	0.15	0.74	0.46	0.35					
HDD	drift	0.52	0.74	0.46	0.35	drift	0.5	0.74	0.46	0.35
Economic Growth	drift	0.39	0.74	0.46	0.35	drift	0.1	0.74	0.46	0.35
Wages	trend + drift	0.2	0.22	0.15	0.12	drift	0.47	0.74	0.46	0.35
Gas based heat rates	drift	0.6	0.74	0.46	0.35	drift	0.1	0.74	0.46	0.35
Coal based heat rates	drift	0.75	0.74	0.46	0.35	drift	0.19	0.74	0.46	0.35
Interest rates	drift	0.23	0.74	0.46	0.35					
share of coal generation	drift	0.42	0.74	0.46	0.35	drift	0.63	0.74	0.46	0.35
coal price * share of coal generation	drift	0.68	0.74	0.46	0.35	drift	0.15	0.74	0.46	0.35

Note: The Null Hypothesis for the KPSS test is stationarity, so that a test value greater than the critical value indicates non-stationarity.

Table 4.6: Summary of Unit Root Test Results

Variables	Visual inspection of Graphs	ADF	PP	KPSS
		Based on critical values at a 5% significance level		
Electricity Price	growth	I(1)	I(1)	I(0)
Coal based Capacity	growth	I(1)	I(1)	I(1)
Gas based Capacity	growth	I(1)	I(1)	I(1)
Coal price	growth	I(1)	I(1)	I(0)
Gas price	growth	I(1)	I(1)	I(0)
Coal based utilization ratio	unit root	I(1)	I(1)	I(1)
Gas based utilization ratio	unit root	I(1)	I(1)	I(0)
HDD	Stationary	I(0)	I(0)	More than I(1)
Economic Growth	Stationary	I(0)	I(0)	I(0)
Wages	Growth	I(1)	I(1)	More than I(1)
Gas based heat rates	stationary with break	I(1)	I(1)	I(1)
Coal based heat rates	Stat	I(0)	I(0)	I(1)
Interest rates	unit root	I(1)	I(1)	I(0)
share of coal generation	unit root	I(1)	I(1)	I(0)
coal price * share of coal generation	Growth + stationary part	I(1)	I(1)	I(1)

4.4.4.2 Analysis taking account of Non Stationarity

In view of the results concerning non-stationarity, all variables except growth, heating degree days, coal-based heat rates, and the interest rate were first differenced and the model was re-estimated. In this case, changes in the electricity price are being explained by changes in the other variables (but by the levels of the four non-differenced variables). Results are shown in Table 4.7.

In view of the first differencing of most of the variables, the estimation period is now from 1966 to 1997, with results shown in Columns (1) and (2) of Table 4.7. As with the levels model in Table 4.1, there is again evidence of first-order autocorrelation (but not of any higher order), and this is alternately dealt with using standard errors based on an autocorrelation-consistent covariance matrix estimator (as in Column (1)),[44] or by estimating a first-order autoregressive (AR(1)) model, as reported in Column (2) of Table 4.7. The estimated autoregressive parameter in this latter case is 0.48, and is significantly different from both one and zero. These models fit the data reasonably well, (R-squared values of 0.7554 and 0.7760) and diagnostic tests revealed no evidence of autocorrelation, heteroskedasticity, or misspecification. Estimation was also performed using the longer pre-restructuring estimation period from 1965 to

[44] Again, the order of the autocorrelation-consistent covariance matrix estimator that is used is 2, although the results were not materially affected with different choices.

2000, and these results, again using standard errors based on an autocorrelation-consistent covariance matrix estimator are reported in Column (3) of Table 4.7.

TABLE 4.7: Pre-Restructuring Period Estimation Results, First-Differenced Model

Variable	1966-1997		1966-2000
	(1)	(2)	(3)
coal capacity	0.0001 (0.0001)	-0.00001 (0.0003)	0.0002 (0.0001)
nat. gas capacity	0.0010** (0.0003)	0.0005 (0.0005)	0.0002 (0.0004)
coal price	-4.1728 (6.287)	-4.6170 (7.884)	-3.5699 (6.054)
nat. gas price	0.6152** (0.1840)	0.5822** (0.1532)	0.3776* (0.1679)
coal utilization ratio	-0.0019 (0.0016)	-0.0026 (0.0059)	-0.0028 (0.0028)
nat. gas utilization ratio	0.0024 (0.0063)	0.0027 (0.0084)	0.0027 (0.0074)
heat rate of coal	-0.00005 (0.00005)	-0.0001 (0.0001)	-0.0001 (0.0001)
heat rate of nat. gas	0.0001* (0.00003)	0.00004 (0.00005)	-0.00001 (0.00004)
coal share of generation	0.2186 (0.7598)	0.1307 (1.740)	0.7525 (1.0750)
coal price * share coal	7.1621 (6.672)	7.0687 (8.361)	5.8640 (6.8080)
heating degree days	-0.000004 (0.00007)	0.00001 (0.0001)	0.0001 (0.0001)
growth	-0.0263** (0.0079)	-0.0284** (0.0111)	-0.0164* (0.0077)
wage rate	0.0008 (0.0082)	-0.0051 (0.0113)	-0.0148 (0.0101)
interest rate	0.0234 (0.0205)	0.0137 (0.0260)	0.0371* (0.0154)
constant	0.5881 (0.7525)	0.8231 (1.143)	0.5872 (0.8205)
R-squared	0.7554	0.7760	0.6804
autocorrelation coefficient (rho)		0.4849** (0.1546)	
number of observations	32	32	35

Notes: 1. **, *, and † indicate significance at the 1%, 5%, and 10% levels, respectively.

2. Numbers in parentheses are estimated standard errors, which in Columns (1) and (3) are based on an autocorrelation consistent (Newey-West) covariance matrix.

3. All variables – including the dependent variable but excluding heating degree days, coal-based heat rates, growth, and the interest rate – are first differenced.

Based on the first column of Table 4.7, natural gas capacity, the natural gas price, the natural gas-based heat rate, and economic growth have statistically significant effects, at least at a 5% significance level. Compared with the results in the first column of Table 4.1, where non-stationarity was suspected of being a cause of the unexpected signs for some of the estimated coefficients, coal capacity no longer has a significant positive effect, the heat rate of natural gas and natural gas capacity now both have significant and positive effects rather than being insignificant, the coal share of generation and the interest rate now both have insignificant effects rather than significant negative effects, and economic growth which was insignificant now has a negative and significant effect. The positive and significant effect of natural gas prices is essentially unchanged in the two tables. Overall, the signs on all statistically significant estimates are as expected once non-stationarity is accounted for except for the economic growth variable, since higher economic growth presumably reflects higher electricity demand, which would be expected to result in higher electricity prices.

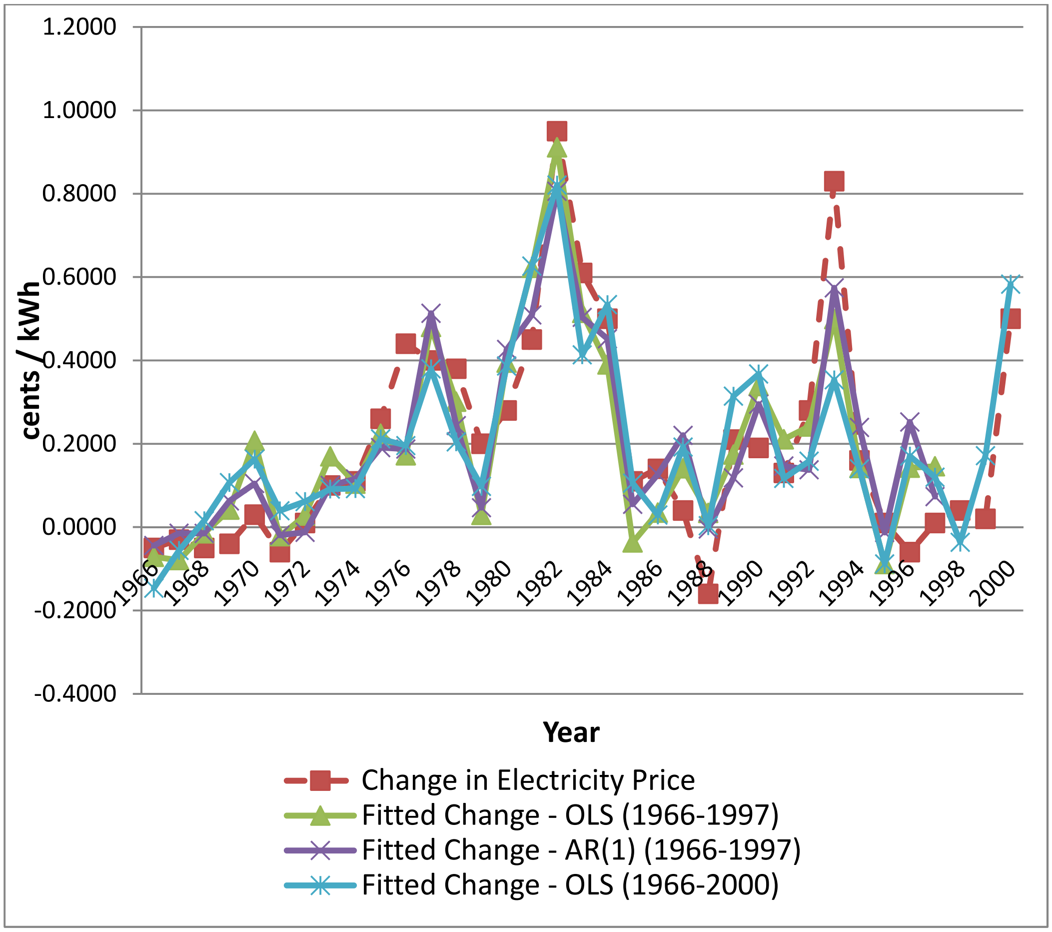
Fewer variables are significant in Columns (2) and (3) of Table 4.7, although those that are significant have the same signs and generally similar magnitudes to the estimates in Column (1). However, neither natural gas capacity nor the heat rate of natural gas has a significant effect in either Column (2) or (3). In contrast, the interest rate does have the expected positive and significant effect in the Column (3) results.

The unexpected sign on economic growth, as well as the insignificance of some of the other coefficients, raises questions about the usefulness of counterfactual (post-restructuring period forecast) prices based on such a model. While perceived model deficiencies will always cause concerns about the forecasts that are based on such a model, improvements require a better modelling framework, or better data, or both. Given that the model here was developed carefully based on mimicking a COS approach and through a review of the relevant literature, the most obvious scope for improvements is through the use of a better data set. For example, utilization of a detailed plant-level set for both the pre- and post-restructuring periods, were it to be available, might be expected to yield better estimation results. The assembling such a data set is, however, well beyond the scope of this thesis, although it might be usefully considered in future work.

Based on the province-level data set that could be assembled here, the counterfactual electricity prices obtained using the estimates reported in Table 4.7, for a model that mimics the COS methodology, might be expected to be better than those computed using a model based on a strict COS methodology. Following the COS framework strictly fails to account for the endogeneity, as mentioned in Section 4.2.1.1, that results from the variables being measured in terms of output as opposed to being measured in their natural units. Further, counterfactual electricity prices obtained using the estimates of the model developed here would also be expected to be preferable to those appearing in the literature that are not based on a comprehensive structural model of the determinants of the electricity price.

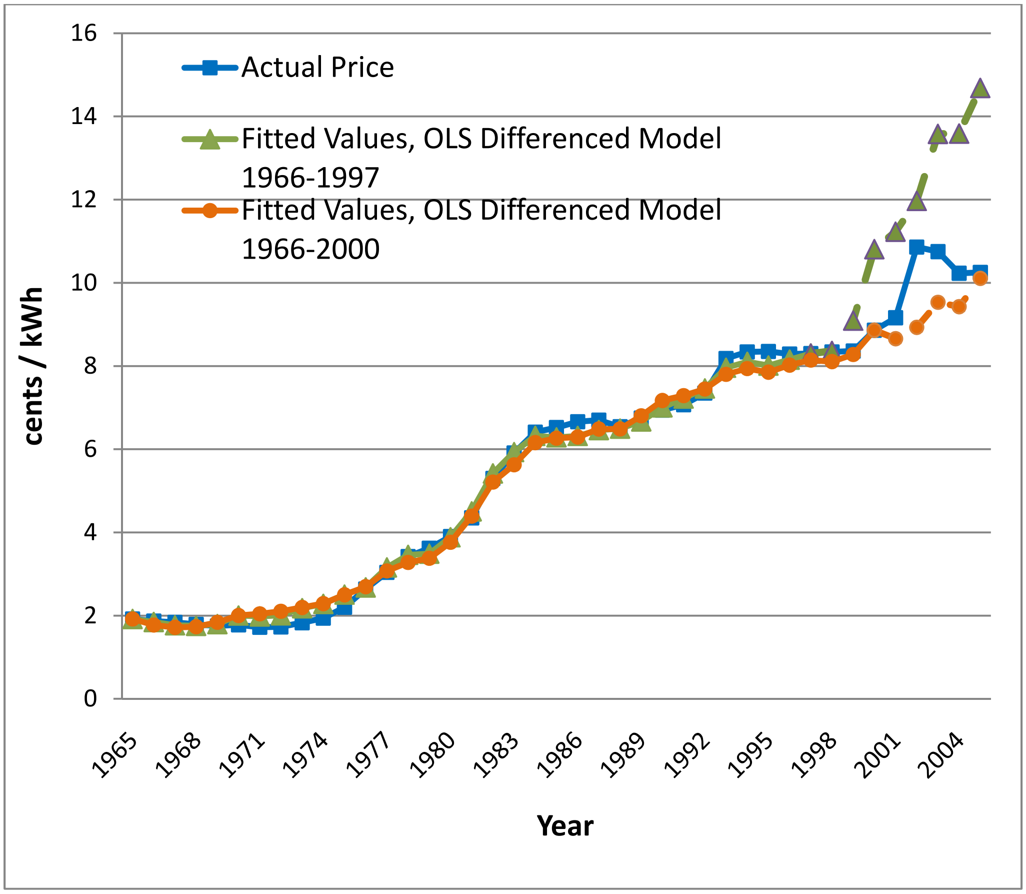
Figure 4.16 shows the fitted values for the three estimated models in Table 4.7. The three sets of fitted values are generally similar to each other, but compared to the fitted values for the levels model shown in Figure 4.13 which track actual prices very well, the fitted values from the model in first differences do not track the actual price changes very well in some periods, particularly when these actual price changes are quite large (in either direction).

Figure 4.16: Actual and Fitted Changes in Electricity Prices, Pre-Restructuring



Using the parameter estimates reported in Columns (1) and (3) of Table 4.7, estimated using data for 1966 to 1997 and 1966 to 2000, respectively, predictions of changes in the electricity price (using observed values of the explanatory variables for the prediction period) were obtained to 2005. These fitted values of changes in electricity price are difficult to reconcile with the actual changes, since if the model under-predicts the change in one period, it would have to over-predict the change in the next period just to be close to the actual price. As a result, the estimated price changes may differ greatly from the actual price changes even though the model's predictions of the level of the price might be quite close. To deal with this issue, the fitted price changes from the models for the estimation period were added to the actual price in 1965 to obtain fitted values of prices for the estimation period. Then, for each model, the predicted price changes for the post-restructuring period were added to the predicted value at the end of the pre-restructuring period (which for both series turned out to equal the actual price in that year) to obtain a series of predicted electricity prices for the post-restructuring period. The complete set of fitted (for the pre-restructuring period) and predicted (for the post-restructuring period) price changes are shown in Figure 4.17 along with the actual price series.

Figure 4.17: Actual and Fitted Electricity Prices based on Differenced Models



As can be seen from Figure 4.17, both models fit the actual prices quite well during the pre-restructuring period (which ends in 1997) for the Model in Column (1) of Table 4.7 and in 2000 for the model in Column (3) of Table 4.7. However, in the post-restructuring period, the model that has the pre-restructuring period ending in 1997 does not do very well, with fitted values much larger than actual values in all post-restructuring years. The model with the pre-restructuring period that ends in 2000 yields predicted prices for the post-restructuring period that are below the actual prices throughout this period, although the difference is quite small in 2005. As with the models estimated in levels form, it appears to be important to utilize as much information as possible from the pre-restructuring period, that is, by using information right up to the end of this period.

To complete the analysis, we focus just on the first-difference model estimated with the longer pre-restructuring estimation period that ends in 2000. For the post-restructuring period beginning in 2001, Figure 4.18 shows the predicted (forecast) prices from this model (as in Figure 4.17) along with the actual prices and 95% confidence bounds for the forecast prices.

Figure 4.18: Actual Prices and 95% Confidence Bands for Counterfactual Prices obtained from the First-Difference Model (Estimated for 1966-2000)

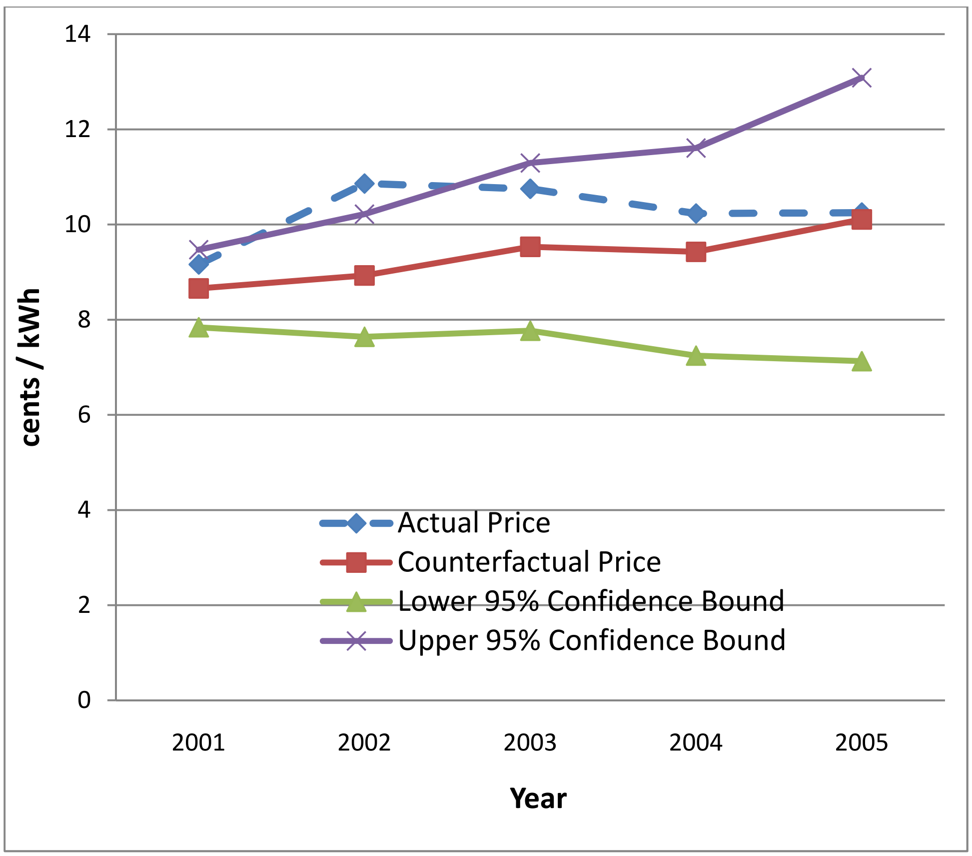


Figure 4.18 shows that apart from 2002, the upper 95% confidence bound lies above the actual price, so that the actual prices cannot be viewed as being statistically significantly greater (using a 5% level of significance) than the counterfactual prices except in this one year. Thus, only in 2002 is the price with

restructuring significantly higher than the price that would have been observed if restructuring had not occurred. However, in all years the lower 95% confidence bound lies below the actual price, so that based on this analysis, restructuring has not resulted in a retail electricity price that is significantly lower than what would have been experienced had restructuring not occurred. Thus, in general, the results from the first differenced model, estimated for the pre-restructuring period ending in 2000, support the conclusions reached using the model with the same pre-restructuring period, but where the variables are in levels form.

4.5 Summary and Conclusion

The main objective of the analysis in this chapter is to assess whether the residential electricity price in Alberta in the post-restructuring period, from 2001 onwards, is lower or higher than it would have been had restructuring not occurred. To investigate this issue, a structural model of the determinants of electricity prices in Alberta in the period prior to restructuring is developed. This model is estimated using data for the pre-restructuring period, and then based on the estimates of the parameters of the model, actual values of the explanatory variables in the post-restructuring period are substituted into the estimated model to yield forecast electricity prices for this later period. These counterfactual electricity prices for the post-restructuring period are compared with the prices actually observed in order to assess the effects of restructuring on residential electricity prices.

Although our findings are limited somewhat by small amount of data available in the post-restructuring period, the results of this analysis, particularly in the case where the model is estimated from 1965–2000, tend to indicate that at least for the first four years after restructuring, retail prices did increase above the level that would have been expected had restructuring not occurred. However, confidence intervals that are constructed suggest that the actual prices are not statistically significantly (at a 5% level) higher than the counterfactual prices except in 2002 and possibly 2003. The results differ a little depending on whether the structural model of the determinants of electricity prices is estimated in level or first-difference form, although generally the results of these two specifications are quite similar.

Of course a drawback of the approach used to construct the counterfactual prices is that they are obtained using the actual values of the explanatory variables that are observed in the post-restructuring period. However, restructuring itself may have changed the values of the endogenous variables in the post-restructuring period, and this possibility needs to be taken into account. An extension of the analysis that attempts to quantify these effects is developed and applied in Chapter 5.

Appendix 4.1: Calculations of the Price of Capital Services

There are various approaches that can be used to derive a series for the price of capital services, sometimes referred to as the cost of capital. In Section A4.1.1, determination of the user cost of capital is considered, while in Section A4.1.2, the weighted average cost of capital is examined.

A4.1.1 User Cost of Capital

The user cost of capital calculation, defined in (4.5) requires data on the unit price of capital, capital gains, deprecation, tax rates and interest rates. Unfortunately, data on these components for our estimation period 1965-1997/2000 are not readily available either in the rate setting decisions published by the Energy and Utilities Board (formerly AEUB) or in the financial statements issued by the three principal players in the Alberta Electricity market – TransAlta, ATCO and EPCOR. As noted in Section 4.3.5, within a particular firm, much of the information that is required to calculate the user cost of capital might be expected to be known, but to a researcher it is simply unavailable. For example, the unit price of capital could be constructed from the ratio of the capital stock in nominal and in real terms, but this is not available. Likewise, calculation of expected capital gains becomes problematic if the value of the capital stock in each year is not known. Share prices could be used, although these would include other assets of the firms, which might involve very different capital appreciation components. In the absence of other information, it is perhaps not unreasonable to assume that expected capital gains are zero and to assume a unit price of capital of one.

Given these two assumptions, while data on appropriate interest rates for the electricity market can be obtained from the EUB (AEUB) Decisions on electricity rate settings that involved the electricity utilities, information on the depreciation of long-term generation capacity assets and tax rates have to be obtained from the respective financial statements of the three key utilities in the pre-restructuring Alberta electricity market – TransAlta, ATCO and EPCOR. Moreover, even data on interest rates provided in the EUB Decisions are only sporadically available from 1988 onwards for EPCOR and TransAlta, and for 1975 onwards for ATCO.[1] Therefore, in the following, an attempt is made to extract the information on depreciation rates on long-term assets, tax rates, and long-term bond interest rates respectively from the financial statements of the three utilities and consolidate them to assemble the user cost of capital that could be used, notwithstanding the assumptions employed, as the price of capital series.

A4.1.1.1 Depreciation Rates:

Studies from the US Energy Information Administration (*EIA*) usually employ a constant depreciation rate because their analysis is not set in a time

[1] These compiled data are presented in A4.1.2.6.

series econometric framework. However, depreciation rates are crucial in the calculation of the user cost of capital, which forms one of the determinants of electricity price in our time series econometric setting. While depreciation rates for electricity generation utilities are not readily available in Alberta, as noted earlier, the financial statements for ATCO, EPCOR and TransAlta were examined in an attempt to determine these rates.

ATCO financial statements were available from 1974 – 2004 except for 1977, 1981 – 82 and 1990. From the notes to these financial statements, information about depreciation rates can be obtained. From 1974–1980, depreciation rates were available for ‘Industrial Rental Units and Utility Trailers’, whereas from 1983–1994 depreciation rates were defined for ‘Natural gas and electricity utility plants and equipment’. For 1995–1996, composite depreciation rates for electric power in service and under construction were available, and finally from 1997–2004, composite depreciation rates for power generation were available. The depreciation figures from 1974–1980 were constant at 10%, whereas for 1983–1994 the depreciation rates reported ranged from 1.5% to 10.2%. From 1995 to 2004, depreciation rates were generally around 3.5%.

Since depreciation data were provided as a range for 1983-1994 and not as a single percentage figure, we use the yearly average of depreciation rate ranges for the years 1983 – 1994. As far as depreciation rates prior to 1974 are concerned, rates may be available only until 1965 because that is when ATCO Industries Ltd. was amalgamated from Trans Canada Rent-A-Trailer System Ltd., Donson Building Enterprises Ltd., and ATCO Industries Ltd. However, a lack of access to financial statements prior to 1974 precludes this information extraction. It may also be noted that the depreciation rates were extracted from the consolidated financial statements of ATCO Ltd. because separate statements for ATCO subsidiaries, like ATCO Electric, that deal specifically with electricity generation were not available for the 1960 – 2004 time period.

TransAlta Utility Corporation financial statements provided depreciation rates from 1981 to 2004. These rates were provided for mining property and equipment, hydro-based production, thermal-based production, environmental control equipment, transmission lines and distribution equipment and an ‘other’ category. From 1980 to 1991, the overall composite depreciation rates were available, whereas for 1980–1997, cost of capital for property under construction were available and finally from 1988 – 1992, cost of capital for plants for future use were also available. These cost of capital figures ranged from 9.8 to 13.08%, however, since they were not available for the entire 1980 – 2004 period, and since these figures were not available for either ATCO or EPCOR, they were not used in the computation of the overall depreciation rate. For our purposes, depreciation rates directly related to generation were used, that is, depreciation rates for hydro and thermal based generation were averaged to get the overall composite rate of depreciation for TransAlta.

Since the user cost of capital is to be employed as a determinant of electricity prices for domestic uses, technically depreciation rates for transmission must also be included. However, since depreciation rates for transmission are not specifically available for ATCO, and EPCOR further distinguishes between transmission and retail depreciation rates, we simply focus on depreciation rates for generation. Depreciation rates were extracted from TransAlta Utility Corporation financial statements (that provide general information) as opposed to either TransAlta Corporation or TransAlta Power financial statements, as the latter statements are not available prior to 1998.

Composite depreciation rates were available for EPCOR Utilities Inc., which was formed in 1996, from 1998 – 2004 for the category generation plant and equipment, and from 2001 – 2004 for the categories electricity transmission and distribution and retail systems and equipment. For our purposes, the figures under the category generation plant and equipment were used as they were available over a longer time period than the depreciation rates for the other two categories. It may also be noted that depreciation rates were extracted from EPCOR Utilities financial statements as opposed to from financial statements of EPCOR Power as the latter did not provide depreciation rates.

For simplification purposes, a simple average of depreciation rates across ATCO, TransAlta and EPCOR was computed in order to obtain composite figures that could be used in the calculation of the user cost of capital. The results are presented in Table A4.1.1, in which the shaded parts indicate that for ATCO an average was taken for the depreciation ranges and for TransAlta the depreciation rates for hydro and thermal based generation were averaged.

It is clear from Table A4.1.1, that the discrepancy of high and low depreciation rates between 1974 – 1980 and 1981 – 2004 should be resolved, ideally by obtaining data for TransAlta and EPCOR for the missing years as well as extending the depreciation rates as close to 1960 as possible. It may be recalled, though, that since ATCO was formed in 1965 and Edmonton Power, the predecessor to EPCOR, was formed only in 1970, it would be difficult to extend the depreciation rates series back to 1960 as this would require that we look into financial statements of the companies that were merged to form ATCO and of the predecessor companies to Edmonton Power. Moreover, depreciation rates may not be available for the same categories as are available for later years. On this basis, in future work it may be preferable to assume a constant depreciation rate, as done by the EIA.

Table A4.1.1: Composite Depreciation Rates

Year	ATCO	TransAlta	EPCOR	average
1974	10%			10.00%
1975	10%			10.00%
1976	10%			10.00%
1977				
1978	10%			10.00%
1979	10%			10.00%
1980	10%			10.00%
1981		3.06%		3.06%
1982		3.26%		3.26%
1983	4.4%	3.26%		3.81%
1984	5.1%	3.74%		4.40%
1985	4.0%	3.74%		3.85%
1986	4.0%	3.74%		3.85%
1987	4.0%	3.74%		3.85%
1988	4.4%	3.74%		4.05%
1989	4.4%	3.18%		3.79%
1990		3.18%		3.18%
1991	5.9%	3.33%		4.59%
1992	5.9%	3.32%		4.59%
1993	5.9%	3.32%		4.59%
1994	5.9%	3.32%		4.59%
1995	3.60%	3.32%		3.46%
1996	3.50%	3.32%		3.41%
1997	3.40%	3.29%		3.34%
1998	3.80%	3.27%	3%	3.36%
1999	3.30%	3.73%	3.10%	3.38%
2000	3.30%	3.73%	3.50%	3.51%
2001	3.40%	5.23%	3.60%	4.08%
2002	3.40%	10.75%	3.50%	5.88%
2003	3.40%	10.75%	3.70%	5.95%
2004	3.40%	10.75%	3.60%	5.92%

A4.1.1.2: Tax Rates

Another component of the user cost of capital comprises tax rates that apply to interest and depreciation expenses. The financial statements of ATCO Ltd, TransAlta Utility Corporation and EPCOR Utilities Inc. provide income tax rates, which are appropriate to use as they are obtained from the income statements, that is, the same source as the interest and depreciation expenses. ATCO financial statements provide statutory income tax rates for 1983 – 2004 excluding 1993 and effective income tax rates from 1983 – 1987 and from 1996 - 2004. Effective tax rates are found after adjusting the statutory rates for allowances for equity funds during construction, crown royalties and other nondeductible payments to government, earned depletion and resource allowance rebates among other adjustments.

The TransAlta statements provide statutory income tax rates from 1980 – 2004, whereas effective income tax rates are available only from 1980 – 1995 and 1999 – 2004. As opposed to both ATCO and TransAlta financial statements, EPCOR statements provide only statutory income tax rates for 1998 - 2004. Moreover, for 1998 and 1999, EPCOR statements provide a combined federal and provincial income tax rate of 45% as opposed to a proper statutory income tax rate.

For our purposes we will use the average of statutory income tax rates of the three utilities. Table A4.1.2 provides the average income tax rates. It may be difficult to extend this series back to 1960 because ATCO and EPCOR utilities were formed in 1965 and 1970 respectively and also the fact that financial statements of ATCO do not provide income tax rates from 1974 – 1980.

Table A4.1.2: Average Income Tax Rates

Year	ATCO	TransAlta	EPCOR	average
1980		48.80%		48.80%
1981		48.80%		48.80%
1982		48.80%		48.80%
1983	48.60%	47.90%		48.25%
1984	47.60%	47.00%		47.30%
1985	47.00%	47.90%		47.45%
1986	48.35%	48.80%		48.58%
1987	48.62%	50.60%		49.61%
1988	47.38%	47.70%		47.54%
1989	43.84%	43.80%		43.82%
1990	43.84%	43.80%		43.82%
1991	44.22%	44.20%		44.21%
1992	44.34%	44.30%		44.32%
1993		44.30%		44.30%
1994	44.34%	44.30%		44.32%
1995	44.57%	44.60%		44.59%
1996	44.60%	44.62%		44.61%
1997	44.60%	44.62%		44.61%
1998	44.60%	44.62%	45%	44.74%
1999	44.60%	44.62%	45%	44.74%
2000	44.60%	44.62%	44.60%	44.61%
2001	43.10%	43.10%	41.60%	42.60%
2002	42.20%	39.30%	39.10%	40.20%
2003	41.70%	36.80%	36.60%	38.37%
2004	40.90%	33.90%	33.87%	36.22%

Given the above limitations, and despite the variability apparent in Table A4.1.2, in future work it might preferable to assume a constant income tax rate across time.

A4.1.1.3: Interest Rates

Interest rates could be used as a proxy to the capital costs as captured by the user cost of capital especially in absence of information on depreciation and tax rates. Average interest rates on new long-term utility debt are available from 1962 – 1999 from EPC. These rates are traced back to McLeod Young Weir Ltd. Alternative rates were obtained from CANSIM as well. The following series were selected owing to their long-term nature, which tallies with the life of the generation plants and also because financial statements of electricity utilities refer to long-term debt.

- Series V122544, Selected Government of Canada Benchmark Bond Yields: Long Term, available monthly from 1976 – 2005.
- Series V122487, Government of Canada Marketable Bonds, Average Yield, Over 10 Years, available monthly from 1936 onwards.
- Series V122488, McLeod, Young and Weir Bond Yield Averages: 10 Provincials, available monthly from 1948 – 1988.
- Series V122517, Scotia Capital Inc., Average Weighted Yield: Provincials Long Term, available monthly from 1977 (Nov) – 2005.
- Series V122518, Scotia Capital Inc., Average Weighted Yield: All Corporations Long Term, available monthly from 1977 (Nov) – 2005.

Only the V122487 series interest rate is available for the full 1965-2006 period. This rate closely mimics the EPC rate as the correlation between the two for 1962 - 1999 is 0.9935. The other interest rates also have very high correlation rates with the EPC-based interest rate as indicated in Table A4.1.3.

Table A4.1.3: Correlations between EPC and CANSIM based Long-term Interest Rates

Interest rate series	years	correlation
(EPC:V122544)	1976-1999	0.9933
(EPC:V122487)	1962-1999	0.9935
(EPC:V122488)	1962-1988	0.9986
(EPC:V122517)	1978-1999	0.9991
(EPC:V122518)	1978-1999	0.9999

Examination of the balance sheets of electric utilities may provide more information as well as corroboration for the rate at which utilities borrow to construct their generation plants. Therefore, interest rates on long-term debt along with the duration of maturity of the respective debts were obtained from the financial statements of ATCO, EPCOR and TransAlta. From 1974 – 1980, ATCO borrowed some of its long-term debt at prime rates, which are vaguely defined as being either Canadian prime, banks best commercial lending rate, banks best US lending rate, US base rate to Canadian borrowers or London Interbank Offering rate LIBOR. From 1997 – 2001, ATCO also borrowed at Bankers Acceptance (BA) rates, however, for our preliminary analysis we will abstract from both the prime and BA rates and focus on averaging the interest rates that are directly provided by the financial statements.

Average interest rates computed from ATCO financial statements are available from 1974 – 2004, except for 1977, 1981-82 and 1990 as these statements were not available. Several interest rates were available for TransAlta Utility Corporation from 1981 – 2004 including mortgages, debentures, notes payable, capital leases amongst other categories, which were simply averaged to get an overall interest rate for TransAlta. Finally as far as EPCOR is concerned, we have interest rates for various levels of maturity available from 1998 – 2004. These rates, having a maturity period range from 1 – 25 years, fall in the 6.8 to 11.62% range and are denoted as obligations to the City of Edmonton. Also reported are debentures, with interest rates ranging from 4.6 to 6.95%, with maturity dates up to 2029.

The average interest rates from ATCO, TransAlta and EPCOR were averaged to obtain a composite interest rate value. Likewise, the years to maturity for the three utilities were averaged to obtain an average period over which the long-term debt was borrowed. Table A4.1.5 provides the details for the three utilities and Figure A4.1.1 depicts the various interest rates from Table A4.1.3, along with the average interest rates computed from the financial statements of the three utilities.

Figure A4.1.1 clearly shows a spike in the interest rates in the early 1980s and thereafter a gradual decline to a more or less pre-1980s level interest rates. This figure also indicates that, while the EPC interest rate is closely correlated with the CANSIM-based interest rates, the correlation between the average interest rate from the utilities and all the other interest rates is quite low compared to the correlation between the EPC and the CANSIM based rates. These correlations are presented in Table A4.1.4 along with the periods over which they are computed. Since average interest rates are not available for 1977 because no financial statements were available for that year, correlations were also computed separately from 1978 onwards.

Figure A4.1.1: Alternative Interest Rates (%)

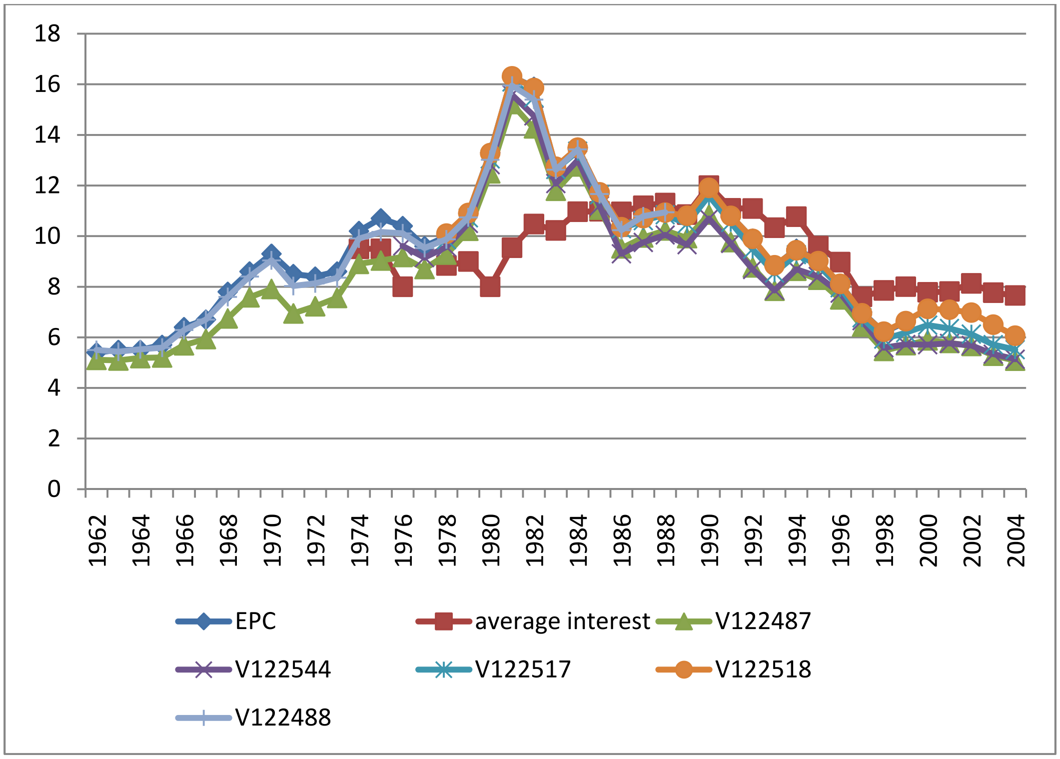


Table A4.1.4: Correlations between Average Interest Rates of the Utilities and Other Long-term Interest Rates

Comparison Interest Rate series	sample period	correlation	sample period	correlation
EPC	1974-1999	0.3951	1978-1999	0.4077
V122487	1974-2004	0.5924	1978-2004	0.6075
V122544	1976-2004	0.5494	1978-2005	0.5687
V122517	1978-2004	0.6158	1978-2004	0.6158
V122518	1978-2004	0.5973	1978-2004	0.5973
V122488	1974-1988	0.1183	1978-1988	-0.0957

Table A4.1.5 indicates that the average interest rates fall in the 7.6 to 12% range, whereas the average borrowing period falls in the 9 to 31 year range. Since the utilities have several long-term debts at various rates and terms to maturity, a simple average of the interest rates and the terms to maturity may not be appropriate and perhaps some weighting scheme should be introduced, which may in turn raise the correlation between the averaged interest rates and the other interest rates. However, the issue of maturity period would remain, for the CANSIM interest rates are defined for a long-term period or over ten year period without the specification of the exact time duration, whereas the exact average time period of maturity are obtained for the three utilities.

Table A4.1.5: Average Interest Rates and Years to Maturity

Year	ATCO	TransAlta Utility Corp.	EPCOR Utilities Inc.	Average interest rate	ATCO	TransAlta Utility Corp.	EPCOR Utilities Inc.	Average years to maturity
	Interest rates				Years to maturity			
1974	9.50%			9.50%	11			11
1975	9.50%			9.50%	10			10
1976	8.00%			8.00%	9			9
1977								
1978	8.84%			8.84%	15			15
1979	9.00%			9.00%	14			14
1980	8.00%			8.00%	13			13
1981		9.54%		9.54%		21		21
1982		10.48%		10.48%		20		20
1983	9.97%	10.48%		10.22%	19	19		19
1984	9.97%	11.96%		10.97%	18			18
1985	10.00%	11.96%		10.98%	17			17
1986	10.00%	11.92%		10.96%	16			16
1987	10.03%	12.38%		11.20%	15			15
1988	10.03%	12.58%		11.31%	19			19
1989	10.25%	11.45%		10.85%	18			18
1990		12.00%		12.00%				
1991	10.85%	11.35%		11.10%	11			11
1992	10.83%	11.35%		11.09%	31			31
1993	9.32%	11.35%		10.33%	30			30
1994	10.41%	11.13%		10.77%	29	9		19
1995	10.18%	9.04%		9.61%	28	8		18
1996	9.43%	8.53%		8.98%	27	12		20
1997	7.38%	7.83%		7.60%	26	11		19
1998	6.49%	8.08%	8.99%	7.85%	25	35	31	30
1999	7.34%	7.93%	8.74%	8.00%	24	34	30	29
2000	6.53%	8.20%	8.61%	7.78%	23	33	29	28
2001	6.97%	8.10%	8.37%	7.81%	33	32	28	31
2002	8.29%	8.10%	8.02%	8.13%	32	31	27	30
2003	7.57%	7.73%	7.99%	7.77%	31	30	26	29
2004	7.57%	7.40%	7.99%	7.65%	30	29	25	28

Given data limitations, the averaged interest rates cannot be used because they are not available for the 1962 – 1973 period and many values for later years, specifically for TransAlta and EPCOR, are missing. A data availability criterion leaves us with only the CANSIM series V122487 for subsequent regression analysis purposes, for even the rates based on EPC are only available until 1999.

A4.1.1.4: User Cost of Capital Calculation

In our analysis we assume expected capital gains to be zero, ignore the depreciation rate and tax considerations, and focus on the main component, namely interest rates simply because the information on depreciation and tax rates is not available for 1962 - 1973. Moreover, as noted in A4.1.1.3, notwithstanding the simplifying assumptions used in their computation, even the data on interest rates based on the financial statements of the three utilities are only available from 1974-2004.

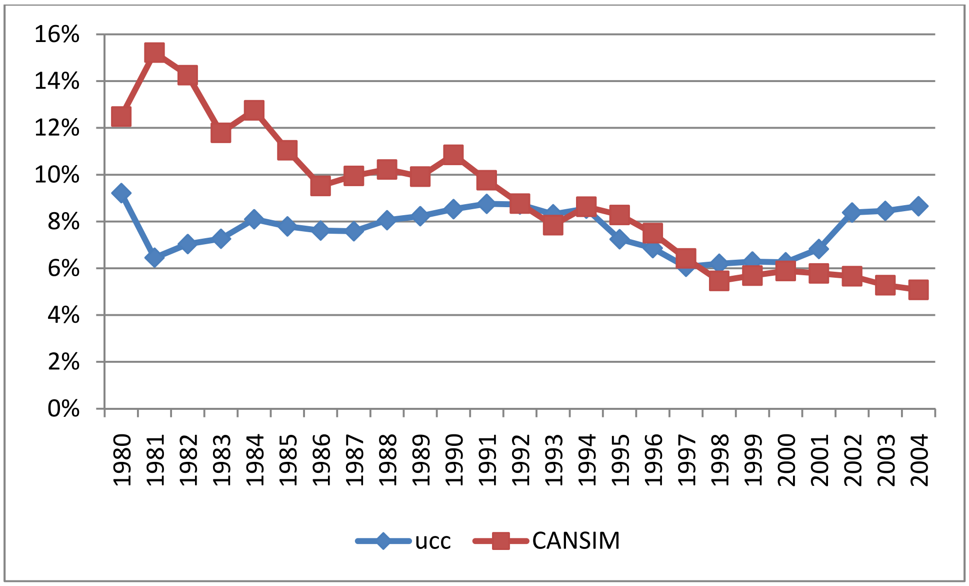
Despite data availability issues and other limitations, we can compute an approximate user cost of capital for the 1980 – 2004 period given the information on depreciation and tax rates and the average interest rates based on the financial statements of the three utilities. Table A4.1.6 and Figure A4.1.2 depict this user cost of capital (UCC).

Table A4.1.6: User Cost of Capital

Year (1)	Depreciation rate (2)	Income Tax rate (3)	Interest rate (4)	UCC (5)=[(2)+(4)]*(1-(3))
1980	10.00%	48.80%	8.00%	9.22%
1981	3.06%	48.80%	9.54%	6.45%
1982	3.26%	48.80%	10.48%	7.03%
1983	3.81%	48.25%	10.22%	7.26%
1984	4.40%	47.30%	10.97%	8.10%
1985	3.85%	47.45%	10.98%	7.79%
1986	3.85%	48.58%	10.96%	7.61%
1987	3.85%	49.61%	11.20%	7.58%
1988	4.05%	47.54%	11.31%	8.05%
1989	3.79%	43.82%	10.85%	8.23%
1990	3.18%	43.82%	12.00%	8.53%
1991	4.59%	44.21%	11.10%	8.75%
1992	4.59%	44.32%	11.09%	8.73%
1993	4.59%	44.30%	10.33%	8.31%
1994	4.59%	44.32%	10.77%	8.55%
1995	3.46%	44.59%	9.61%	7.24%
1996	3.41%	44.61%	8.98%	6.86%
1997	3.34%	44.61%	7.60%	6.06%
1998	3.36%	44.74%	7.85%	6.19%
1999	3.38%	44.74%	8.00%	6.29%
2000	3.51%	44.61%	7.78%	6.25%
2001	4.08%	42.60%	7.81%	6.82%
2002	5.88%	40.20%	8.13%	8.38%
2003	5.95%	38.37%	7.77%	8.45%
2004	5.92%	36.22%	7.65%	8.66%

The correlation between the interest rate and the user cost of capital over the full sample in Table A4.1.6 is weak at 0.4, which may cast doubt on the appropriateness of using an interest rate as a proxy for the user cost of capital. However, the correlation over the 1983 – 2001 sub-period is much stronger at 0.91, which – in view of the limitations encountered with the other components – helps justify the use of interest rates as a proxy variable for the user cost of capital. Regardless, due to data availability limitations, the CANSIM based interest rate Series V122487 will be used to proxy for the user cost of capital. Unfortunately, the correlation between the user cost of capital and the selected CANSIM interest rate is only 0.1579. Figure A4.1.2 illustrates this weak relationship between the two series.

Figure A4.1.2: User Cost of Capital and the CANSIM V122487 Interest Rate



A4.1.1.5: Summary

Based on the data collected from financial statements, and using assumptions of zero capital gains and a unit price of capital equals of one, data availability issues preclude robust calculations of the user cost of capital to capture the price of capital services in the electricity industry in Alberta. With various additional simplifying assumptions, including simple averaging of various classes of depreciation rates and various classes of long-term bonds, as opposed to using the more data-intensive weighted averages, and essentially ignoring gaping holes in the underlying data set, a rough user cost of capital series was calculated for 1980-2004. However, this is not suitable for use in our empirical work due to the limited time period for which it is available. Moreover, the low correlation between the user cost of capital and the selected CANSIM interest rate series V122487, the only long-run interest rate series for which data are available for

1965-2006, also cast doubts on the use of this interest rate series as a proxy for the user cost of capital, although this may reflect deficiencies in the user cost of capital calculations. This motivates the consideration of an alternative framework to capture the price of capital services, namely the weighted average cost of capital, which is considered next.

A4.1.2 Weighted Average Cost of Capital (WACC)

While the computation of the user cost of capital requires information on the unit price of capital, capital gains, depreciation rates, tax rates and interest rates, the data requirements for the weighted average cost of capital (WACC) generally include the market value of equity, book value of long-term debt, cost of equity based on the CAPM model, yield to maturity on long-term bonds and the corporate tax rate. Calculation of the WACC for Alberta's electric utilities is considered in this section. To begin, the motivation for the WACC is addressed in the electricity market restructuring context in Section A4.1.2.1, then the justification for using the WACC using the CAPM approach is provided in Section A4.1.2.2, followed by the definition of WACC in Section A4.1.2.3. In Section A4.1.2.4 the data sources and components used in the computation of WACC are described, while the actual computations follow in Section A4.1.2.5. Section A4.1.2.6 provides supplementary information about the cost of capital from AEUB Decisions. This is followed in Section A4.1.2.7 by a summary and justification for using the CANSIM based interest rate Series V122487 as a proxy for WACC and hence the price of capital services in the Alberta electricity market.

A4.1.2.1 Motivation for WACC in the Context of Restructuring

Regulated electricity utilities are considered low risk firms due to a combination of stable demand and a guaranteed rate of return under rate of return regulation. The risks that arise under regulation are mainly associated with the regulatory process and include factors such as regulators applying arbitrary figures to the cost of capital and subjectively and selectively using regulatory precedents and reports. However, lower business risk for these firms leads to higher leverage and hence increases their financial risks. (Lockett, 2002)

In a restructured environment however, the return on equity and hence the cost of capital are higher than those for a regulated integrated utility because of the higher risk arising from the removal of the guaranteed rate of return and a lack of access to preferential borrowing rates. Power Pool price volatility increases risks for the generation segment, whereas risks for the transmission segment increase as it becomes more difficult to obtain long-term forecasts of both generation supply and electricity demand for transmission planning purposes. Rapid technological innovation leads to rapid depreciation and obsolescence of the older capital and hence increases the opportunity cost and the user cost of capital associated with operating the older capital, especially for the capital intensive transmission segment. (Cragg, Lehr and Rudkin, 2001)

In the specific context of Alberta, according to a 1999 AEUB hearing report, long-term risks of generation companies would increase under competition because of greater uncertainty in forecasting costs and outage rates, as well as from the hourly power pool price volatility. However, risks for transmission companies remain relatively unchanged from 1996 because of a predictable and stable cost structure. Introduction of competition and customer choice increases long-term risks for the distribution companies because of brokerage and retailing functions in the provision of Regulated Rate Options (AEUB Decision, U99099).

It is perhaps more appropriate to capture the cost of capital by the weighted average cost of capital *WACC* than the user cost of capital or the interest rate on long-term bonds. This is because interest rates may not capture risk as delineated by the weighted cost of capital through the risk premium. In fact, in the early 1980s, rising inflation increased interest rates on bonds; however, the impact on stocks was not as great, which led to a negative relationship between interest rates and risk premiums on utility stocks. (Brigham, Shome, Vinson, 1985) This negative relationship between interest rates and risk premia indicates that capturing risk through interest rates might be misleading for this type of analysis. On the other hand, it was noted in the context of the user cost of capital that share prices could reflect other assets of the firms, which might involve very different capital appreciation components. Notwithstanding that the WACC includes the appreciation of share prices in its computation, given the relevance of WACC in the context of the electricity market restructuring, the following delineates the methodology for the computation of the WACC.

A4.1.2.2 Justification for WACC based on the CAPM Model

WACC is defined as the weighted average cost of raising a dollar of capital at the margin, which includes both bonds and equity. It does not reflect the average cost of capital raised in the past or even the average cost of capital. While the current yield on bonds is used in computing the cost of debt as opposed to the coupon rate (Lockett, 2002), various methods are used to compute the cost of equity, namely the Capital Asset Pricing Model *CAPM* based equity risk premium method, discounted cash flow *DCF* model and the bond yield plus risk premium approach (Brigham and Gapenski, 1997). The comparable earnings method is also used. However, it is sensitive to the accounting practices of the utilities selected for comparison, the business cycle selected for the method, as well as any discontinuities caused by events such as mergers, divestitures or restructuring. Likewise, issues involved with the DCF model include the validity of the growth rate used in the model and the volatility of the growth series selected for the model (AEUB, U99099).

The cost of equity, or alternatively the return on equity, can also be computed using more advanced methods such as Arbitrage Pricing Theory (*APT*) and multi-factor regression models. However, the data requirements for such models can be quite cumbersome; for instance APT may require information on oil prices, interest rates, inflation and GNP growth apart from other variables, whereas multi-factor regression models require data on variables such as profits, accounting ratios and firm size. These methods will not be considered here because, apart from their complexity, none of the major regulatory boards have employed these in their computations of the cost of equity and hence cost of capital. In fact, UK regulators use the CAPM method whereas US regulators use the Dividend Growth model *DGM* method to determine the cost of equity. (Lockett, 2002)

Given the above, and the fact that since the 1990s numerous regulatory boards have used the CAPM based equity risk premium method to determine the cost of equity, for the purposes of computing WACC, the cost of equity will be computed through the CAPM based equity risk premium method. The advantages of this approach include computational simplicity and a strong theoretical foundation. In fact, when compared with the Dividend Growth model, which is a type of DCF model, the CAPM provides a less arbitrary figure for the rate of return on equity (Lockett, 2002). The disadvantages of using the CAPM method include the exclusion of factors that determine risk other than the market portfolio.

However, the key issue with the CAPM based approach is that since electricity utilities have low betas and low growth rates, and given that CAPM based approach understates the risk for firms with low beta, small capitalization or low growth, the risk premium and hence the cost of equity for utilities is understated (Chretien and Coggins, 2008). In fact, there is a great deal of evidence that questions the empirical validity of the CAPM, especially when applied to regulated utilities (Brigham, Shome, Vinson, 1985). Alternatives for computing the cost of equity for utilities could be the Fama French Model or the Adjusted CAPM model. However, these models have not been adopted by regulators in their estimation of cost of equity, and for the purposes of simplicity, the WACC will be computed based on the standard CAPM method.

A4.1.2.3 Determining WACC based on CAPM

The WACC computation is computed using the following formula:

$$WACC = \frac{E}{V}\, r + \frac{D}{V}\, YTM\,(1-t)$$

E: market value of equity = number of shares x common shares outstanding

D: book value of long-term debt

V = E + D

r: cost of equity as determined from the CAPM based risk premium method

YTM: yield to maturity on long-term bonds

t: corporate tax rate

The cost of equity component of WACC is computed using the formula:

$r = r_f + [\, \beta \times (r_m - r_f)]$

where:

r_f is the risk-free rate of interest. Generally, the yield on the 20 year T-Bond is used as the risk free rate in the CAPM model. The risk free rate used in the CAPM model is that of the long-term Treasury bonds as opposed to T Bills as the rates on the former as less volatile, and also because of the fact that most stock holder invest on a long-term basis, which in turn implies that the cost of equity is correlated more with T-bond rates than with T-bill rates (Brigham and Gapenski, 1997). It may also be noted that the cost of equity determined using the long-term bond rate is slightly lower than that based on the T-bill rates (Damodaran, 1997).

β is the sensitivity of the asset returns to market returns, and is computed as the slope coefficient from a linear regression of the firm's stock returns on the market portfolio returns r_m. The stock returns and the market portfolio returns are defined as in Damodaran (1997):

Stock Return = [change in price + dividends] / price

Return on market portfolio (index) r_m = % change in index + dividend yield (on the stocks in the portfolio (index))

Usually, 5 years of monthly past data on stock and market returns are used in the regression as higher frequency data leads to noise in data, whereas data used for longer periods of time may reflect the change in risk of the firm (Brigham and Gapenski, 1997).

$r_m - r_f$ is the risk premium defined as the difference between the market portfolio return and the risk-free rate of interest. It should be noted that ($r_m - r_f$) is not determined by simply computing the yearly differences between r_m and r_f. In fact the risk premium is computed by differencing the arithmetic (geometric) means of historical risk free rates of return from the arithmetic (geometric) means of the historical returns on the market portfolio. The returns computed based on geometric means generally yield a lower risk premium, however, these risk premia take compounding into account and are a better predictor of the average premium in the long run (Damodaran, 1997).

The cost of equity computed from the CAPM based equity risk premium method as outlined above, and the cost of debt as given by the yield on maturity on long-term bonds can be combined together using the percentages of equity and long-term debt in the firm's total capital – the capitalization ratios - to obtain a measure of the WACC. While, the correct weights of debt and equity used in the WACC are not based on book values or on the market values of debt and equity but rather the target weights that the firm aims toward (Brigham and Gapenski, 1997), given data constraints, the market value of equity and the book value of debt will be used in computing these weights.

The cost of capital using weights based on book values is usually lower than that computed based on market values (Damodaran, 1997). However, the use of market value of equity in the WACC calculation will mitigate this phenomenon to some extent as well as capture the effect of unregulated activities of the utilities on the cost of capital. As far as regulated utilities are concerned, the Electricity Utilities Board indicates that book values of capitalization ratios reflect the appropriate financial risks as compared to the market values of capitalization ratios, however, for the purpose of comparing costs of capital before and after restructuring, market-based equity will be used to maintain consistency between the pre- and post-restructuring cost of capital figures. Finally, in the specific context of TransAlta, while the short term debt is part of the permanent feature of its capital structure, and despite the fact that the Electricity Utilities Board has allowed for incorporating short term debt in determining the embedded cost of debt and hence the cost of capital (AEUB, Decision U99099), short term debt will be ignored in our calculations due to data constraints, as it is not clear how to connect the data on yield to maturity *YTM* from FP Bonds with the book values of long and short term debt from the balance sheets, specifically in light of the fact that FP Bonds data will be used, as will become evident from A4.1.2.4.1 and A4.1.2.4.2, due to their availability over a longer time period.

A4.1.2.4 Data Sources

The data components used to compute the WACC, as given in A4.1.2.3, and their respective sources are delineated below.

A4.1.2.4.1 Cost of Debt

Cost of debt, as captured by the yield to maturity (*YTM*) on long-term bonds, was extracted from Financial Post Bonds Series, which are available on a monthly basis as indicated in Table A4.1.7. The respective monthly YTM figures were averaged to obtain annual figures.

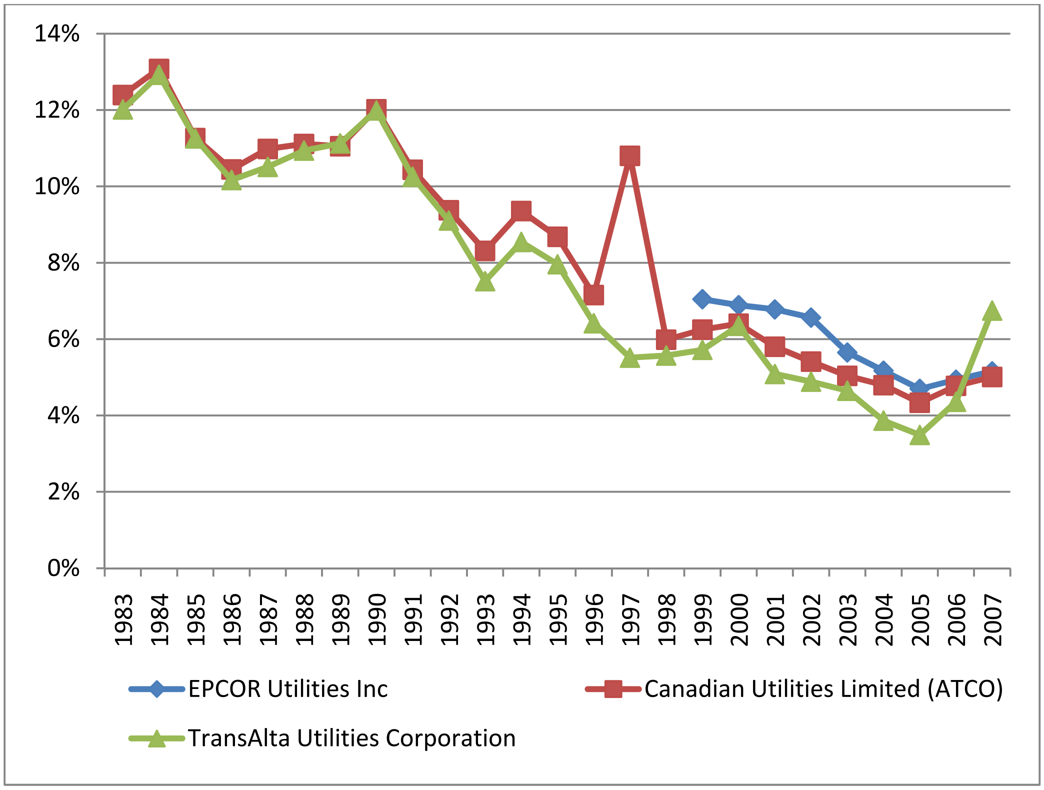
Table A4.1.7: Data Availability for Yield to Maturity

Utility	Data Availability
EPCOR Power LP	2006-2007
EPCOR Utilities Inc	1999-2007
Canadian Utilities Limited	1983-1999, 2002-2007
CU Inc	2000-2007
Trans Alta Utilities Corporation	1983-2007
Trans Alta Corporation	1999-2007

The figures for CU Inc were consistent with those of Canadian Utilities Limited from 1983 – 1999 for the various classes of bonds with varying coupon rates and maturities, and hence both series were combined. The figures for Canadian Utilities Limited from 2002 -2007 did not correspond with the Canadian Utilities Limited data for the various classes of bonds with varying coupon rates and maturities from 1983 – 1999 and hence were discarded in favour of the data from CU Inc. Thus the YTM figures for Canadian Utilities Limited were used as those representing the cost of debt for ATCO, as ATCO Ltd. controls its operations through Canadian Utilities. The YTM figures for EPCOR Power LP and Trans Alta Corporation were also omitted because of availability problems for several years. Thus, the cost of debt is available from 1983 – 2007 for ATCO and Trans Alta and from 1999 – 2007 for EPCOR.

According to Figure A4.1.3, with the exception of the YTM value for Canadian Utilities (ATCO) in 1997, there seems to be a general decreasing trend in the cost of debt and hence, *ceteris paribus,* the cost of capital. Post-2005 this trend seems to have reversed, however not sufficiently to reach the levels seen in the 1980s.

Figure A4.1.3: Yield to Maturity



A4.1.2.4.2 Book Value of Debt

The book value of long-term debt was extracted from both the Financial Post *FP* website as well as the respective balance sheets in millions of dollars for the three utilities. The data from FP were available for ATCO Ltd (1967-2007), TransAlta Corporation (1956-2007) and EPCOR Power LP (1999-2007), whereas the data from balance sheets were available for ATCO Ltd (1995-2007), TransAlta Corporation (1995-2007) and EPCOR Utilities Limited (1998-2007). The figures from the balance sheets and the FP website are clearly not equivalent; however, since the figures from the FP website were available over a longer time period, these figures were selected to capture the book value of long-term debt.

A4.1.2.4.3 Market Value of Equity

The market value of equity is computed by multiplying the number of common shares by the price per share for each of the three utilities. Trans Alta Corporation shares are traded both on the Toronto Stock Exchange as well as the New York Stock exchange. Data on opening, high, low and closing stock prices and the volume traded are available from the yahoo Finance website on a monthly basis from 1995 onwards for the shares traded on the TSE and from 2001 onwards for the shares traded on the NYSE. Weekly data on the shares traded on the NYSE are available from 2001 onwards from the Google Finance website.

The volume of shares traded as well as the high, low and closing share prices are also available on a yearly basis from the FP website for Trans Alta Corporation from 1998 – 2007, although given the single set of figures it is not clear whether these figures represent the shares traded on the TSE or on the NYSE. The Trans Alta balance sheets provide figures on the closing price and the shares outstanding for Trans Alta Power LP from 2000 – 2006. However, since none of the series from the various sources begin prior to 1995, data from Canadian Financial Markets Research Centre *CFMRC* will be used to compute the market value of equity. CFMRC provides monthly data on closing prices as well as the monthly outstanding shares for Trans Alta Corporation, which are multiplied together to obtain the monthly market value of equity and eventually averaged to obtain the annual market value of equity figures. Data on monthly total volume are also available, but only from 1968 onwards; therefore, these figures were not used.

In order to maintain consistency of data sources, CFMRC was also used to obtain the monthly closing prices and shares outstanding for ATCO Class I shares from 1968 onwards. The data on Class II shares were not used as the closing prices are sometimes zero or negative. CFMRC was also used to obtain the relevant data for EPCOR Power LP from 1999 onwards.

A4.1.2.4.4 Data on Preferred Shares

Data on the closing price of the preferred shares and the shares outstanding for the three utilities were available from CFMRC for select years when these preferred shares were being traded. Data on the yields of the preferred shares and number of shares are available from the respective balance sheets of the three utilities. Since there are several types and classifications of preferred shares and these data are only available sporadically for select years, they are not used in the computation of the WACC.

A4.1.2.4.5 Debt and Equity Share Ratios

The book value of debt D obtained from the FP website and the market value of equity E obtained from CFMRC are added together to obtain the value of total capital $V = D + E$. The respective shares of debt and equity in total capital are hence computed as D / V and E / V for ATCO Ltd, Trans Alta Corporation and EPCOR Power LP.

The ratios of Long-term Debt to Common Equity and Total Debt to Common Equity are available at the FP website from 1997 to 2007. The Total Debt to Common Equity ratio is also available from Mergent Online; however, since short term debt was not used in computing WACC, only the ratio of Long-term Debt to Common Equity from the FP website will be considered and compared with the same ratio computed from the combination of data from CFMRC and the FP website.

For comparison purposes, the D/V and E/V ratios for the three utilities were calculated using the Mergent Online data on Total Debt to Common Equity ratios. These were found to be different from the D/V and E/V ratios for the three utilities computed on the basis of the Total Debt to Common Equity ratios obtained from the FP website, although they are roughly of the same order of magnitude.[2] Given that the data available from the combined CFMRC and the FP website sources are available for a longer duration (1980-2006 for ATCO and TransAlta Corporation and 1999-2006 for EPCOR) compared to just the FP website source (1997 onwards for ATCO and TransAlta and 1999 onwards for EPCOR), the data from the former source are used as weights in the calculation of WACC.

A4.1.2.4.6 Corporate Tax Rate

Data on the apparent tax rate are available from the FP website from 1997 – 2007, whereas Mergent Online reports the effective tax rate from 1992 – 2006. Data on statutory tax rates and the effective tax rates are available from 1980, 1983 and 1998 onwards from the balance sheets of ATCO Industries Ltd, Trans Alta Utilities Corporation and EPCOR Utilities Inc., respectively. From 2005 – 2007 the effective tax rate for Trans Alta Utilities Corporation is negative. Given that the statutory tax rate series from the balance sheets is available for the longest time span, it will be used to denote the corporate tax rate in the computation of WACCs for the three utilities. Figure A4.1.4 indicates that from 1996 – 2000, the tax rate more or less remains constant and begins to fall from 2001 onwards. The fall in the tax rate seems to increase the cost of debt and hence the WACC in the post-2001 period, *ceteris paribus*.

[2] The reciprocal of (1+Total Debt/Common Equity) = E/V, and the reciprocal of (1+Common Equity/Total Debt) = D/V.

Figure A4.1.4: Statutory Tax Rates

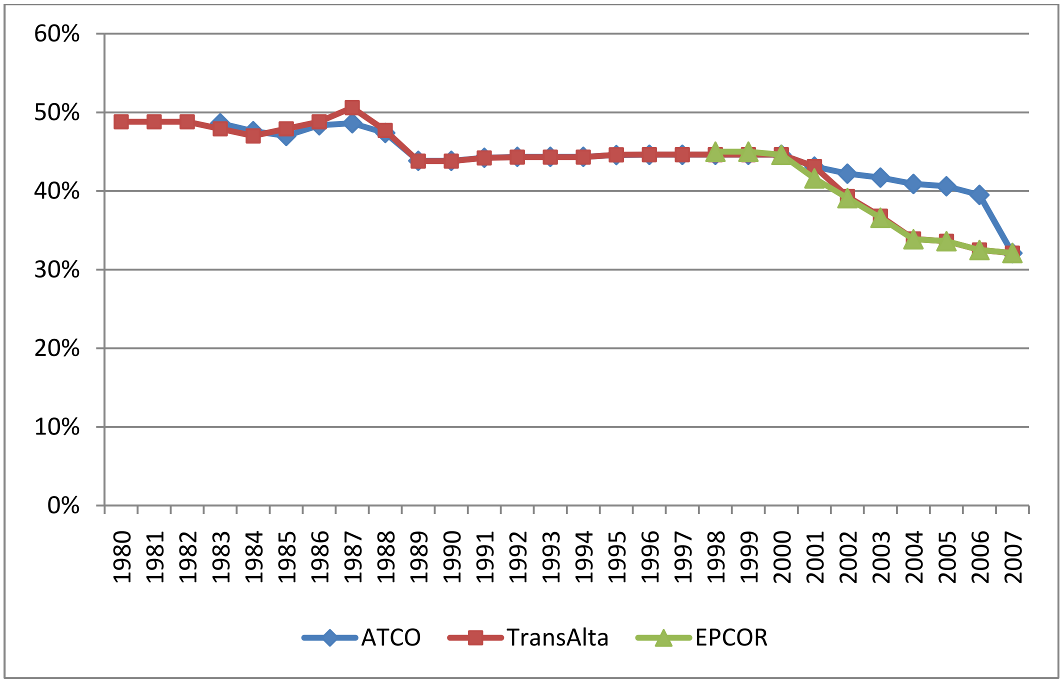
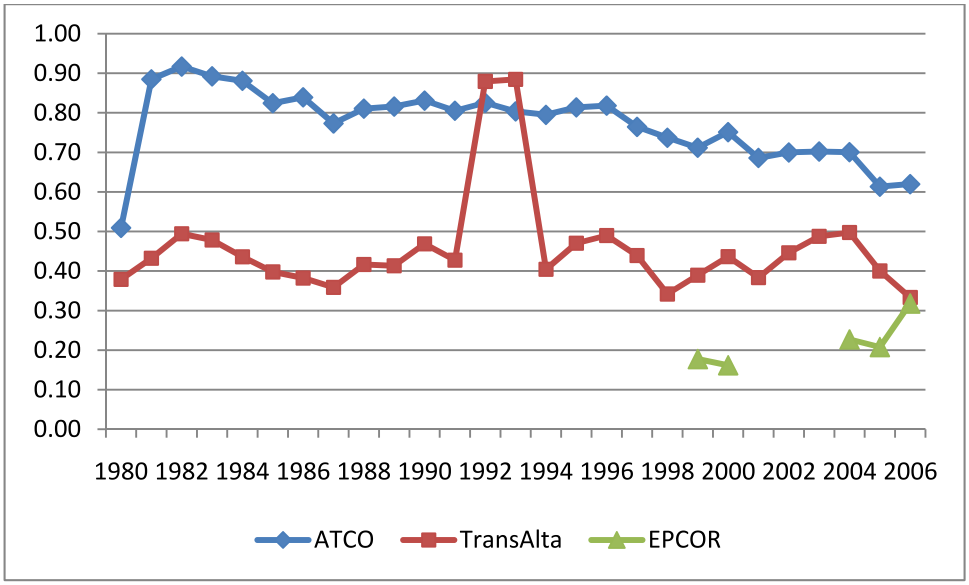


Figure A4.1.5 depicts the share of debt in total capital for the three utilities. While the tax rates are available for Trans Alta Utility Corporation and EPCOR Utilities Inc, and the debt share of capital is available for Trans Alta Corporation and EPCOR Power LP, both of these will be combined in the computation of WACC given the data constraints encountered. The post-2001 decline in tax rates has an impact of raising the cost of debt, however the decline in the share of debt for ATCO from 1996 onwards and the hovering of the Trans Alta share of debt within a band seems to have a mitigating effect of decreasing the cost of debt and hence the WACC in the post-1996 period.

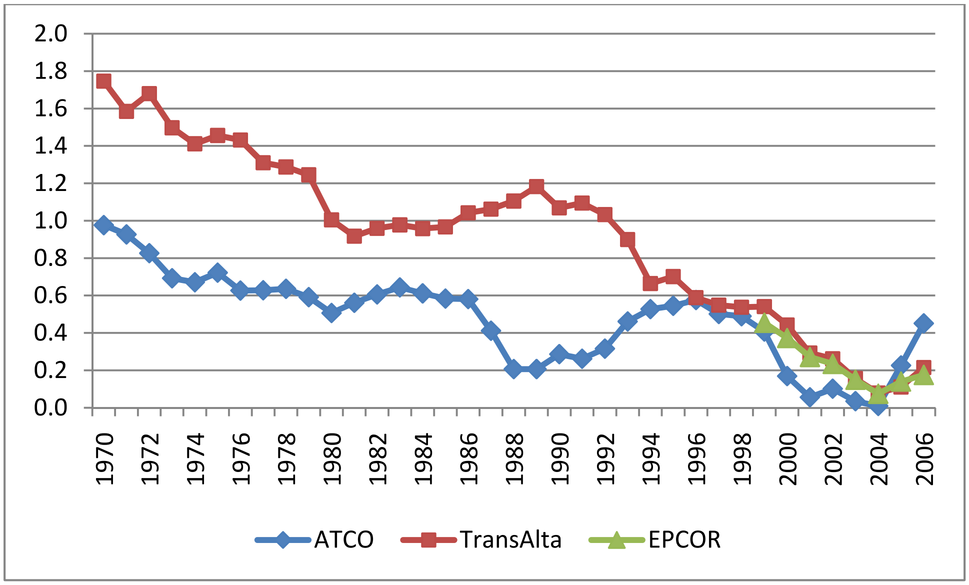
Figure A4.1.5: Debt Share of Capital (D/(D+E))



A4.1.2.4.7 Betas

Data on the betas, used in the computation of the cost of equity part of WACC, for Trans Alta Corporation, Class I shares of ATCO and EPCOR Power LP are available on a monthly basis from CFMRC from 1960- 2006, 1970 – 2006, and 1999 – 2006 respectively. The monthly figures were averaged to obtain annual beta figures for the three utilities. Figure A4.1.6, drawn from 1970 onwards, indicates that the betas have declined over the years following the electricity market restructuring in 1996, indicating a reduction in the risk of the three utilities as compared to the S&P market as a whole in the post-restructuring period from 1996 – 2004. However, around 2005, the betas begin to rise, denoting an increased riskiness of the three utilities. This indicates that, *ceteris paribus*, the cost of equity and hence WACC would be falling from 1996 – 2004, and rising in the post-2004 period.

Figure A4.1.6: Betas



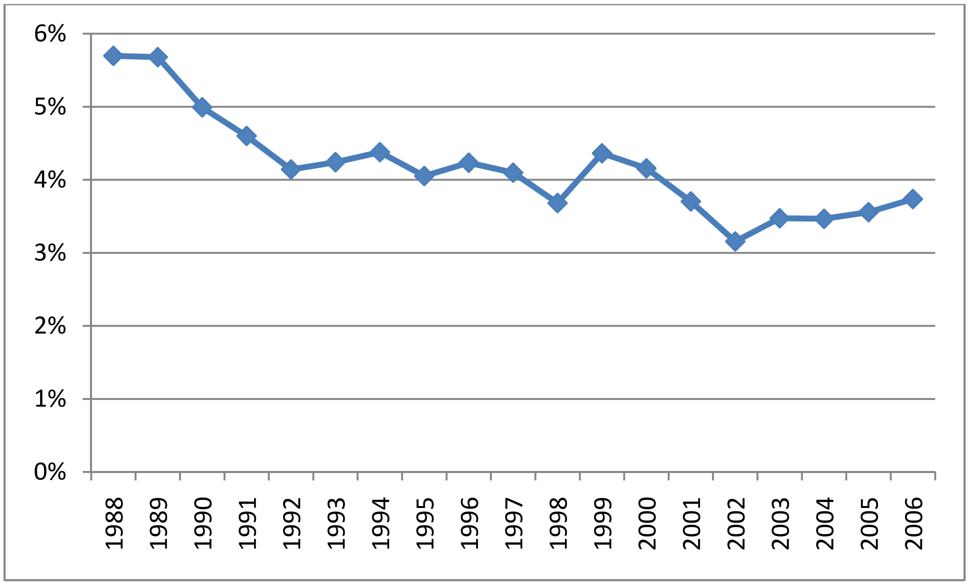
A4.1.2.4.8 Risk Premium

The risk premium was extracted from CFMRC, where it was computed as the difference between the arithmetic (geometric) means of historical risk free rates of return and the arithmetic (geometric) means of the historical returns on the market portfolio. More specifically, the arithmetic (geometric) means of long-term bonds are subtracted from the arithmetic (geometric) means of the S&P/TSX Total Return Index to provide the risk premia figures for 1988 - 2006. For WACC calculations, the geometric means of the risk premium are used because, as mentioned earlier, these risk premia take compounding into account and are a better predictor of the average premium in the long run.

Figure A4.1.7 indicates that the risk premium in general has declined when the post-2001 period is compared with the 1996 – 2001 period, due to a decline in the geometric means of the market index and a rise in the geometric means of the long-term bond interest rates.[3] When the risk premium is viewed in conjunction with the falling trend in the betas of the electricity utilities post 1996, it is clear that the risk for these utilities was declining in the later 1990s.

[3] It is interesting to notice the contrast of the rise in the geometric means of the long-term bond interest rates with the declining yield to maturity post-2000 noted in Figure A4.1.3.

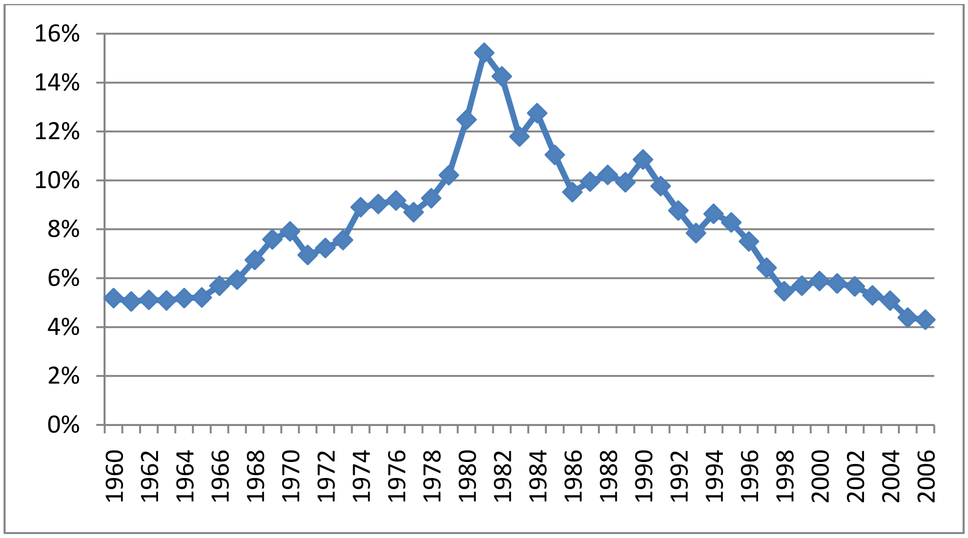
Figure A4.1.7: Risk Premium



A4.1.2.4.9 Risk Free Rate

The risk free interest rate used in computing the cost of equity is different from that used in computing the risk premium portion of the cost of equity, in that the latter uses the geometric mean of the interest rates. The interest rates on long-term bonds are available from 1950 – 2006 from CFMRC. Figure A4.1.8 shows that long-term government bond rates have generally declined after peaking in 1981. These rates also continue to decline after 1994, which indicates, *ceteris paribus*, a decline in the cost of equity and hence the WACC for the post-restructuring period.

Figure A4.1.8: Long-Term Government Bond Interest Rate



A4.1.2.5 WACC Calculation

The components of the WACC, described above in the various sections of A4.1.2.4, can be combined together to compute the WACC using the formulae defined earlier:

$$WACC = \frac{E}{V}\, r + \frac{D}{V}\, YTM\,(1-t) \qquad r = r_f + [\,\beta \times (r_m - r_f)]$$

The trends in the components of the WACC are provided in Table A4.1.8, which indicates that, in general, there would be a decline in the WACC from 1996 onwards.

Table A4.1.8: Impact of the WACC Components

	Components	Trend	Effect on WACC
1	cost of debt	general decreasing trend	-ve
2	statutory tax rates	1996 - 2000 constant, falls post 2001	+ve
3	Debt share	falls post 1996 (loosely)	-ve (given 1,2)
4	Equity share	rises post 1996 (loosely)	-ve (given 5,6,7)
5	Betas	fall 1996 - 2004, rise post 2004	-ve
6	Risk Premium	falls 1999 onwards (loosely)	-ve
7	Risk free rate	falls 1994 onwards	-ve

The calculations for the WACC for ATCO Ltd from 1988 – 2006 are as shown as an illustration in Table A4.1.9, which indicates a decline in WACC and hence the cost of capital in the post-restructuring period, confirming the trends in the components of the WACC as indicated in Table A4.1.8.

Table A4.1.9: WACC Calculation Illustration for ATCO

Year (1)	Data Source							
	FP	CFMRC	FP & CFMRC			FP Bonds	CFMRC	
	LT Debt (millions) (2)	Class I shares (millions) (3)	Total (4) = (2)+(3)	D (5) =(2)/(4)	E (6)= (3)/(4)	YTM* (7)	LT Gov. Bond GM (8)	LT Gov. Bond Rate (9)
1980	101.6	97.9	199.5	0.51	0.49			12.48%
1981	737.8	96.0	833.8	0.88	0.12			15.22%
1982	886.1	80.1	966.2	0.92	0.08			14.26%
1983	890.2	107.4	997.6	0.89	0.11	12.39%		11.79%
1984	878.9	118.7	997.6	0.88	0.12	13.08%		12.75%
1985	794.5	169.2	963.7	0.82	0.18	11.27%		11.04%
1986	893.0	171.0	1,064.0	0.84	0.16	10.44%		9.52%
1987	900.6	264.0	1,164.6	0.77	0.23	10.98%		9.95%
1988	1,006.0	234.9	1,241.0	0.81	0.19	11.11%	5.350%	10.22%
1989	1,188.2	268.0	1,456.2	0.82	0.18	11.05%	5.615%	9.92%
1990	1,342.9	273.1	1,616.0	0.83	0.17	12.02%	5.578%	10.85%
1991	1,348.8	326.2	1,674.9	0.81	0.19	10.44%	6.004%	9.76%
1992	1,438.3	304.3	1,742.6	0.83	0.17	9.37%	6.167%	8.77%
1993	1,491.0	364.3	1,855.3	0.80	0.20	8.31%	6.529%	7.85%
1994	1,469.9	379.0	1,848.9	0.80	0.20	9.35%	6.136%	8.63%
1995	1,942.2	444.5	2,386.7	0.81	0.19	8.68%	6.548%	8.28%
1996	2,433.4	540.6	2,974.0	0.82	0.18	7.16%	6.717%	7.50%
1997	2,486.2	765.4	3,251.6	0.76	0.24	10.80%	6.936%	6.42%
1998	2,633.1	939.1	3,572.2	0.74	0.26	5.99%	7.079%	5.47%
1999	2,604.9	1,054.5	3,659.4	0.71	0.29	6.25%	6.781%	5.69%
2000	2,799.5	926.4	3,725.9	0.75	0.25	6.41%	6.913%	5.89%
2001	2,701.0	1,236.5	3,937.5	0.69	0.31	5.80%	6.856%	5.78%
2002	2,946.9	1,263.6	4,210.5	0.70	0.30	5.41%	6.919%	5.66%
2003	2,843.1	1,205.6	4,048.7	0.70	0.30	5.04%	6.889%	5.30%
2004	3,176.7	1,357.4	4,534.1	0.70	0.30	4.79%	6.969%	5.08%
2005	3,292.5	2,074.8	5,367.3	0.61	0.39	4.33%	7.109%	4.39%
2006	3,425.1	2,101.1	5,526.2	0.62	0.38	4.78%	7.043%	4.30%

Note: *YTM figures are for Canadian Utilities Limited;

…continued

Table A4.1.9 (continued)

Year (1)	Data Source					
	CFMRC		**FP + CFMRC + FP Bonds**			
	Betas Class I shares (10)	Risk Premium GM (11)	ROE (12)= (9)+(10)* (11)	COK (13)= (5)*(7) + (6)*(12)	Statutory Income Tax rate (14)	COK (15)= [1 – (14)]*(5)*(7) + (6)*(12)
1980	1.004					
1981	0.917					
1982	0.959					
1983	0.978				48.60%	
1984	0.958				47.60%	
1985	0.967				47.00%	
1986	1.042				48.35%	
1987	1.062				48.62%	
1988	1.105	5.696%	16.52%	12.14%	47.38%	7.87%
1989	1.183	5.679%	16.64%	12.08%	43.84%	8.13%
1990	1.069	4.992%	16.19%	12.73%	43.84%	8.35%
1991	1.095	4.600%	14.80%	11.29%	44.22%	7.57%
1992	1.033	4.142%	13.04%	10.01%	44.34%	6.58%
1993	0.900	4.241%	11.66%	8.97%	**44.34%****	6.01%
1994	0.664	4.378%	11.54%	9.80%	44.34%	6.50%
1995	0.701	4.052%	11.12%	9.13%	44.57%	5.99%
1996	0.589	4.234%	10.00%	7.67%	44.60%	5.06%
1997	0.549	4.097%	8.67%	10.30%	44.60%	6.62%
1998	0.537	3.681%	7.44%	6.37%	44.60%	4.40%
1999	0.541	4.362%	8.05%	6.77%	44.60%	4.78%
2000	0.443	4.157%	7.73%	6.73%	44.60%	4.59%
2001	0.292	3.704%	6.86%	6.14%	43.10%	4.42%
2002	0.262	3.156%	6.49%	5.73%	42.20%	4.14%
2003	0.156	3.473%	5.84%	5.28%	41.70%	3.80%
2004	0.078	3.466%	5.35%	4.96%	40.90%	3.59%
2005	0.111	3.557%	4.78%	4.51%	40.60%	3.43%
2006	0.215	3.736%	5.10%	4.90%	39.50%	3.73%
Average Cost of Capital			**1988-1995**	10.77%	**1988-1995**	7.12%
			1996-2006	6.30%	**1996-2006**	4.41%

Note: ** Interpolated for 1993.

Likewise, the WACC for Trans Alta and EPCOR are determined for 1988-2006 and 1999 – 2006 respectively, corresponding to periods of data availability, and a similar decline is observed for the WACC computed for these two utilities.

The data sources for the three utilities are provided in Table A.4.1.10. Note that except for the data on YTM and statutory tax rates, the data on other components used in WACC calculation are consistent in that in each case they are extracted for the same utility firm.

Table A4.1.10: Data Source Summary for the WACC components

WACC Component	ATCO	Trans Alta	EPCOR	Data Source
LT Debt Value	ATCO Ltd	Trans Alta Corporation	EPCOR Power LP	FP
Equity Market Value	ATCO Ltd	Trans Alta Corporation	EPCOR Power LP	CFMRC
Statutory Tax Rates	ATCO Industries Ltd	Trans Alta Utility Corporation	EPCOR Utilities Inc.	Balance Sheets
YTM	Canadian Utilities Limited	Trans Alta Utilities	EPCOR Utilities	FP Bonds
Risk free rate	LT Government Bond			CFMRC
Beta	ATCO Ltd	Trans Alta Corporation	EPCOR Power LP	CFMRC
Risk Premium	S&P/TSX Index Rate GM - LT Government Bond Rate GM			CFMRC

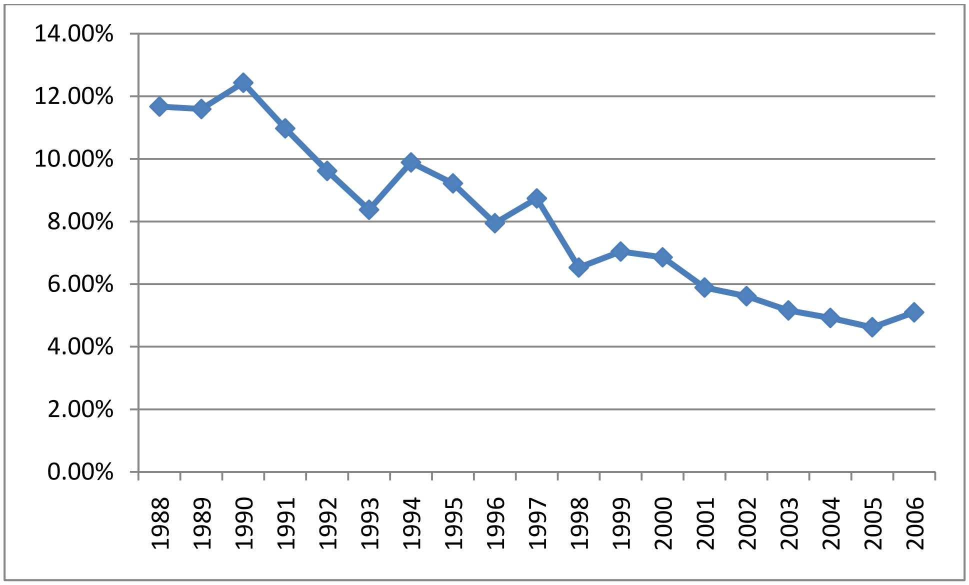
The cost of capital given by WACC is computed from 1988 – 2006, given data availability constraints as indicated in Table A4.1.11. The cost of capital calculation is limited by data on YTM and the risk premium. Given the data on the market price index and the risk-free rate of return, the respective geometric means may be computed to extend the risk premium series back to 1960. However, even if the computations on the risk premium are extended to 1960, the WACC calculations will still be limited by the data on YTM which are available only until 1983.

Table A4.1.11: Data Availability for WACC Components

Data Availability	ATCO	Trans Alta	EPCOR
LT Debt Value	1967-2007	1956-2007	1997-2007
Equity Market Value	1968-2006	1960-2006	1997-2006
Statutory Tax Rates	1983-2007	1980-2007	1998-2007
YTM	1983-2007	1983-2007	1999-2007
Risk free rate	1950-2006		
Beta	1970-2006	1960-2006	1999-2006
Risk Premium	1988-2006		
Market Price Index	1956-2006		

The WACCs for all three utilities are averaged to obtain the overall WACC for the electricity market industry. A weighted average could be computed, wherein the weights could be based on the generation capacity of the three utilities. However, these data are only available from 1983 – 1998 from the Alberta Electric Industry *AEI* Annual Statistics Series. These data may be extended prior to 1983, but data after 1998 are not available for those series. Figure A4.1.9 is based on simple averages and indicates, as expected from Table A4.1.8, a general decline in the cost of capital starting at the onset of restructuring; that is from 1997 onwards.

Figure A4.1.9: WACC



A4.1.2.6 Cost of Capital data from AEUB Decisions

The WACC can only be computed for 1988-2006, which is an even shorter duration than was feasible for the user cost of capital, which was computed from 1980 onwards. In light of this limited data availability, as noted earlier, interest rates and the cost of capital data were also extracted from the AEUB Decisions for the three utilities, from 1988 onwards for EPCOR and TransAlta and from 1975 onwards for ATCO. However even these data are available only on a limited and sporadic basis. Nevertheless, for comparison purposes, they are presented below in Tables A4.1.12, A4.1.13 and A4.1.14. It is interesting to note that despite differences in these figures, the trend toward a lower cost of capital is generally clear based on the information contained in these three tables.

Table A4.1.12: AEUB Decision-based Interest Rate for EPCOR

Year	Decision	Debt	Common equity rate of return	Cost of Capital rate
1988	E89096		13.50%	
1990	E89097	10.50%	13.50%	
	E91074	10.78%	14.00%	11.66%
1993	E92111	9.70%		
1994	E93094	9.00%	11.875%	9.76%
1994	E93094			
1994	E94095		11.875%	
1995	E94095		11.875%	
1996	U97065	10.26%	11.25%	10.60%
	U99099		9.25%	

Table A4.1.13: AEUB Decision-based Interest Rate for TransAlta

Year	Decision	Debt	Return on Equity	WACC EXCL-CIAC
actual 1988	E89091	11.56%	13.50%	11.53%
1989	E89091	11.27%	13.50%	11.36%
1988	E89096		13.50%	
	E89097	10.50%	13.50%	
1990	E89091	11.19%	13.50%	11.33%
1991	E91093	11.182%	13.500%	11.23%
1992	E91093	10.958%	13.250%	11.05%
1993	E93053	10.62%	11.88%	10.41%
	E93094	8.05%	11.875%	
1994	E94095	8.75%	11.875%	
1995	E94095		11.875%	
1996	U97065	8.50%	11.25%	9.37%
	U97065	10%	11-12%	
	U98124	9.621%	12.25%	10.51%
	U99099		9.25%	
2004	2004-052		9.60%	

CIAC: Contribution in Aid of Construction

Table A4.1.14: AEUB Decision-based Interest Rate for ATCO

Year	Decision	Debt	Common equity rate of return	After Tax Cost
1975	E76118		13.36%	10.05%
1976	E76118		14.39%	10.37%
1977	E78001	8.96%	14.20%	10.27%
1978	E78001	9.21%	14.18%	10.29%
1980	E81163	10.02%	14.75%	11.59%
1981	E81163	10.23%	14.75%	11.72%
1982	E82194	11.73%	17.00%	12.84%
1989	E89095		13.50%	
1990	E89095	11.29%	13.50%	11.29%
1988	E89096		13.50%	
	E89097		13.50%	
1991	E91095	11.32%	13.50%	11.28%
1991	E92039	11.32%	13.50%	11.28%
1992	E92039	11.16%	13.25%	11.09%
	E92111	9.60%		
1993	E93069	10.99%	11.88%	10.59%
1994	E93094	8.85%	11.88%	
	E94095	8.75%	11.88%	
1996	U97065	8.50%	11.25%	
2002	2002-082	7.25%	9.50%	7.60%
2005	2006-024	5.53%		
2006	2006-024	5.93%	8.93%	

A4.1.2.7 Summary

Based on the methodology in A4.1.2, the WACC was computed for 1988-2006. However, as for the user cost of capital, several simplifying assumptions were required to allow for computation, including, but not limited to, simple averaging as opposed to weighted averaging, merging data series from different companies of the same parent, and ignoring preferred shares. In view of these limitations, the correlation between the CANSIM long-term interest rate series V122487 and the WACC series was computed to determine whether the CANSIM series, available for the full sample period of 1965-2000 could be used as a reasonable proxy. Given that the correlation between these series is 0.974 for 1988-2006, so that the two series track each other reasonably well, this provides some justification (that was not evident in the user cost of capital context, given the poor correlation there) for using the CANSIM interest rate series to capture the price of capital services. Notwithstanding the use of this proxy CANSIM interest rate series, determination of a better user cost of capital series would be a useful avenue for future work.

Chapter 5: Determining Counterfactual Electricity Prices after Accounting for Endogeneity

5.1 Introduction

In the previous chapter, the electricity price was modelled as a function of a number of explanatory variables, and the parameters of this function were estimated using data for Alberta from the pre-restructuring period. Subsequently, the estimated parameters were used with observed values of the explanatory variables in Alberta in the post-restructuring period to determine counter-factual values of the electricity price, that is, the price that would have been expected to result if restructuring had not occurred. Finally, these counter-factual forecast prices were compared to observed electricity prices in Alberta to determine the effects of restructuring on electricity prices.

The approach used to construct the counter-factual prices is based on the assumption that the values of the explanatory variables in the post-restructuring period were unaffected by the restructuring. In other words, these explanatory variables were treated as being exogenous in the post-restructuring period. However, it is well known that restructuring is accompanied by a multitude of changes. For instance, electricity restructuring – that is, moving from a regulated to a largely deregulated environment – may affect such factors as heat rates – by increasing the incentives for firms to act efficiently, generation capacity – by allowing firms to react to perceived market needs, and the fuel mix – by making it more feasible for firms to employ natural gas-based electricity generation. To the extent that the values of the explanatory variables in the post-restructuring period are affected by the restructuring that occurred, the results of the counter-factual analysis that treats them as being unaffected by the restructuring may be misleading. For example, suppose that a particular explanatory variable has an estimated coefficient of +0.05 in the electricity price function. If this variable has an observed value of 10 in a post-restructuring year, its estimated contribution to the electricity price in this year would be $0.05 \times 10 = +0.5$. Now suppose that in the absence of restructuring the value of this variable in this same year would have been 8 rather than 10, so that its contribution to the electricity price in this year would have been $0.05 \times 8 = +0.4$. By failing to take the endogeneity into account, the counterfactual price in this year will be higher by 0.1 (0.5 – 0.4), making it either closer to, or further from, the observed price in this year, thereby making it appear that the restructuring had a larger or smaller effect on the electricity price than was actually the case.

To deal with this endogeneity problem, the appropriate values of the explanatory variables that should be used in the post-restructuring period to construct the counter-factual Alberta prices are those that would have been observed in Alberta had restructuring not occurred. Unfortunately, since restructuring did take place, these are not available, so that it is necessary to use an alternative approach to determine these values.

An ideal approach would be to find another jurisdiction that mimics Alberta except that it did not restructure its electricity industry. In this case, values of the explanatory variables in this other jurisdiction in the period subsequent to restructuring in Alberta could be used in place of the observed Alberta values in this period to construct the counter-factual prices. Of course no other jurisdiction is likely to mimic Alberta exactly, but it may be possible to find one that mimics Alberta reasonably well in key areas, including the method by which electricity is generated, the extent of interconnections to other jurisdictions, etc.

If it is not possible to find another jurisdiction that mimics Alberta closely, at least in key areas, another possible approach is to identify alternative jurisdictions that are similar to each other except that one restructured their electricity industry while the other did not. In such a case, information about the differences between the values of the explanatory variables in these two jurisdictions subsequent to restructuring could be used to make adjustments to the observed values of the Alberta variables in the post-restructuring period in order to determine likely values for these variables in Alberta if restructuring had not occurred. Of course, such analysis would be subject to considerable uncertainty, and it would be necessary to take this uncertainty into account when constructing the counter-factual electricity prices in Alberta.

In this chapter, both of these approaches are considered. Specifically, other Canadian and US jurisdictions are examined to determine (a) whether they are sufficiently similar to Alberta that the values of the explanatory variables in Alberta in the post-restructuring period could be replaced with values from one of these other jurisdictions that did not restructure, and (b) whether the likely effect of electricity industry restructuring on the explanatory variables in Alberta can be determined by comparing values of these variables from other jurisdictions that did and did not undertake such restructuring. Subsequently, the values of endogenous explanatory variables in Alberta in the post-restructuring period are replaced with values in which the effects of the restructuring have been removed, and the analysis in the previous chapter is repeated, with construction of a new set of counter-factual prices that is then compared with the prices that were actually observed in Alberta in the post-restructuring period.[1]

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[1] It is important to note that the driving factors leading to restructuring in the US differ from those in Alberta, and this may have implications for using information based on the US experience to make adjustments to values of variables in Alberta. Specifically, possibly the main factor leading to restructuring in the US was the relatively high electricity prices in some areas like the eastern region from the mid-Atlantic to the north, as well as in California, while prices were lower in neighbouring areas. Nuclear cost overruns were likely a major factor also. In contrast, jurisdictions where electricity prices were relatively low – often where cheap coal was available – generally showed little interest in restructuring. Few, if any, US jurisdictions present similar conditions to pre-restructuring Alberta, in terms of having relatively low electricity prices, access to cheap coal, and no nuclear generation. On the other hand, using information from the full array of US jurisdictions is essential, as no single US jurisdiction matches the Alberta electricity environment in terms of key variables. In contrast to other Canadian jurisdictions, data are readily available for all 51 US jurisdictions, so that it is possible to use them all in the analysis.

In terms of the explanatory variables that are considered under either of these approaches, the relevant consideration is the electricity price function that was used for determining the counter-factual forecasts in the previous chapter. Specifically, in that analysis, Alberta residential electricity prices were modelled as a function of natural gas- and coal-based capacity, utilization ratios and heat rates, economic growth (as a proxy for growth in electricity demand), heating degree days, an interest rate (as a proxy for capital costs), wages (to reflect operation costs) and coal and natural gas prices (to represent fuel costs). The share of coal-based generation was also included in the function, as was the product of this share and the coal price.

The explanatory variables that are likely to have been affected by restructuring, which we refer to as endogenous variables, include natural gas- and coal-based capacity and other variables that are dependent on these variables, that is, utilization ratios and heat rates as well as the share of coal based generation and its product with the coal price. Generation and generation capacity variables are included in this list because, as mentioned earlier, restructuring initiatives would be expected to affect the generation mix by making it more feasible to employ natural gas-based plants. Likewise, restructuring would impact heat rates by providing incentives to increase generator plant efficiency. Since the impact of restructuring on the generation mix would affect how generator plants are run, the utilization ratios of coal and natural gas-based electricity generating plants would also likely be affected. Restructuring might also affect capital and operation costs, in which case it would also be appropriate to include a capital cost measure and wages among the list of variables potentially affected by restructuring. However, in view of the problems associated with extracting cost of capital data for the different jurisdictions (and the fact that the interest rate proxy that is used in Chapter 4 does not exhibit any intra-country variation), and questions about the representativeness of the wage data that could be obtained, in the subsequent analysis both these variables are treated as though they have been unaffected by restructuring. Both HDD and economy-wide growth rates are also treated as being unaffected by restructuring, and while restructuring may have an indirect effect on fuel prices by impacting the generation mix, since many other factors impact fuel prices, these prices will be treated as exogenous. Thus, in the following analysis, the focus will be on the following endogenous explanatory variables: coal- and natural gas-based capacity, heat rates, utilization ratios, and the share of coal-based generation.

The outline of the remainder of this chapter is as follows. In Section 5.2 data from various Canadian jurisdictions are examined to determine if one of these jurisdictions matches Alberta sufficiently to use its information in the post-restructuring period in Alberta to adjust the values of the endogenous variables in Alberta during this period. Since this is found not to be the case, the restructuring status of US jurisdictions is examined in Section 5.3, with data and data issues pertaining to these jurisdictions considered in Section 5.4. Section 5.5 begins the analysis of the US data. Here, by comparing US jurisdictions that restructured and those that did not, the initial focus is on determining whether there are any apparent effects of restructuring on electricity prices, and whether some or all of the explanatory factors included in our model of electricity prices appear to be associated with these differences. The primary objective here is in determining whether particular attention should be paid to certain of these variables when making adjustments to the Alberta values in the post-restructuring period. A comparison of electricity prices, and of the values of various explanatory variables, in Alberta and the various US jurisdictions, is provided in Section 5.6, which sets the stage for the analysis in Sections 5.7 and 5.8. The analysis in Section 5.7 is concerned with determining both restructured and non-restructured US jurisdictions that have electricity systems and environments that most closely mimic key aspects of the situation in Alberta, while Section 5.8 reports on attempts to perform a similar matching exercise between restructured and non-restructured jurisdictions in the US. Based on these matches, two approaches are developed in Section 5.9 to adjust the values of the values of the endogenous variables in Alberta in the post-restructuring period in order to take the endogeneity into account when constructing the counterfactual post-restructuring forecasts. These approaches are applied in Sections 5.10 and 5.11 to yield counterfactual electricity prices for Alberta in the post-restructuring period that take account of the possible endogeneity of some of the explanatory variables in the model used to determine electricity prices. While Section 5.10 develops and applies a relatively straightforward approach based on the matches described in Section 5.7, a more comprehensive approach developed and applied in Section 5.11 utilizes probability distributions and simulations that make use of the information in Section 5.8 and take account of some of the uncertainty surrounding this information. With both approaches, sensitivity analysis is used to assess the extent to which the results obtained are qualitatively dependent on the particular models used and matches that are made. Section 5.12 contains a summary and conclusions. Finally, based on the analysis and results in this chapter, a critical assessment of the main arguments advanced by the only other study of restructuring in Alberta that uses a counterfactual approach is provided in Appendix 5.2.

5.2 Canadian Jurisdictions

Among Canadian provinces, only Ontario and Alberta have restructured their electricity markets in terms of opening both the wholesale and retail markets to competition (Brennan, 2008). While a key motivation behind the restructuring initiatives in Alberta was to keep supply current with the rising electricity demand, one of the main motivations behind Ontario's restructuring was to improve the fiscal and operational performance of Ontario Hydro – the main electricity provider there under regulation (Tetrault, 2006). Since, for the purpose of adjusting the values of the relevant endogenous variables in Alberta in the post-restructuring period, data are required on similar variables in that period in a comparable non-restructured environment, an appropriate starting point is to consider relevant data from provinces other than Ontario to determine which province best mimics Alberta in terms of key electricity market variables.

Focusing first on generation capacity shares, the information in Table 5.1 indicates the share of generation capacity from various fuel sources in the non-restructured Canadian jurisdictions. For most of these jurisdictions the data are for the year 2000, but for Nova Scotia, PEI, Yukon, and the NWT, data pertain to either 2006 or 2007, which of course are during the post-restructuring period in Alberta.

Table 5.1: Information on Installed Generation Capacity Shares in Alberta and Non-Restructured Canadian Jurisdictions

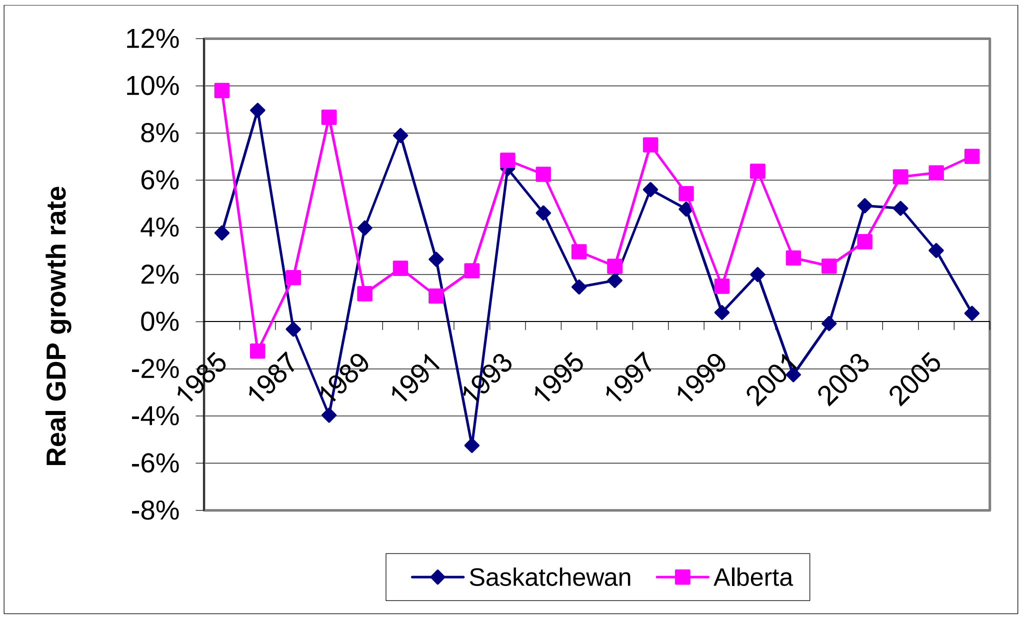
Jurisdiction	**Alberta**	**Saskatchewan**	**BC**	**Manitoba**	**Quebec**	
Year	2000	2000	2000	2000	2000	
Coal	58.00%	53.31%				
Natural gas	31.70%	12.15%	9.99%			
Hydro	8.92%	27.43%	90.01%	95.40%	93.06%	
Nuclear						
petroleum						
Total (MW)	9,692	3,110	11,110	5,219	32,655	
Jurisdiction	**NF & L**	**NB**	**NS**	**PEI**	**Yukon**	**NWT**
Year	2000	2000	2006	2007	2007	2006
Coal			74.27%			
Natural gas				29.26%		3.00%
Hydro	87.27%	23.42%	21.10%		98.95%	31.68%
Nuclear		16.82%				
petroleum		51.10%		41.48%		65.32%
Total (MW)	7,250	3,775	1,706	250	77	164

Source: Respective annual reports of the principal electricity utilities: Saskatchewan Power, New Brunswick Power, Manitoba Hydro, Hydro Quebec, BC Hydro, and Newfoundland and Labrador Hydro. Data for Alberta were collected from the annual reports of the Alberta Energy and Utility Board, and for the other provinces, data from the fact sheets of the Centre for Energy (http://www.centreforenergy.com/FactsStats) were used.

The information in Table 5.1 indicates that in terms of determining the non-restructured province that best mimics Alberta, jurisdictions like PEI, Yukon, and the NWT can be ignored as they have quite small values of total generation capacity shares. As far as provinces like BC, Manitoba, Quebec, and Newfoundland and Labrador are concerned, since the primary source of electricity generation in these locations is hydro-based, these provinces cannot reasonably be compared to Alberta given Alberta's heavy dependence on coal- and natural gas-based generation. Likewise, New Brunswick has a substantially different generation capacity share mix than does Alberta. This leaves only Saskatchewan, bordering on Alberta, which appears to have a somewhat similar generation capacity share mix. In order to ascertain whether external conditions have been similar in both provinces, Saskatchewan and Alberta are compared below on the basis of fuel prices and electricity demand.

Figure 5.1 shows annual real GDP growth in Alberta and Saskatchewan for the period 1985 to 2006. As noted earlier, GDP growth is used in the electricity price function as a proxy for growth in electricity demand. As this figure shows, the growth rate of real GDP in Alberta is always higher than that of Saskatchewan except for a few years: 1986, 1989-1991 and 2003. This indicates that electricity demand has typically been growing faster in Alberta than in Saskatchewan, especially in the post-restructuring period, with the exception of 2003. Over the period 1985 to 2000 (prior to restructuring in Alberta), real GDP grew at an average annual rate of 4.06% in Alberta compared to 2.8% in Saskatchewan, while subsequently, from 2001 to 2006, the corresponding rates are 4.65% in Alberta and 1.8% in Saskatchewan.

Figure 5.1: Annual Growth in Real GDP in Alberta and Saskatchewan

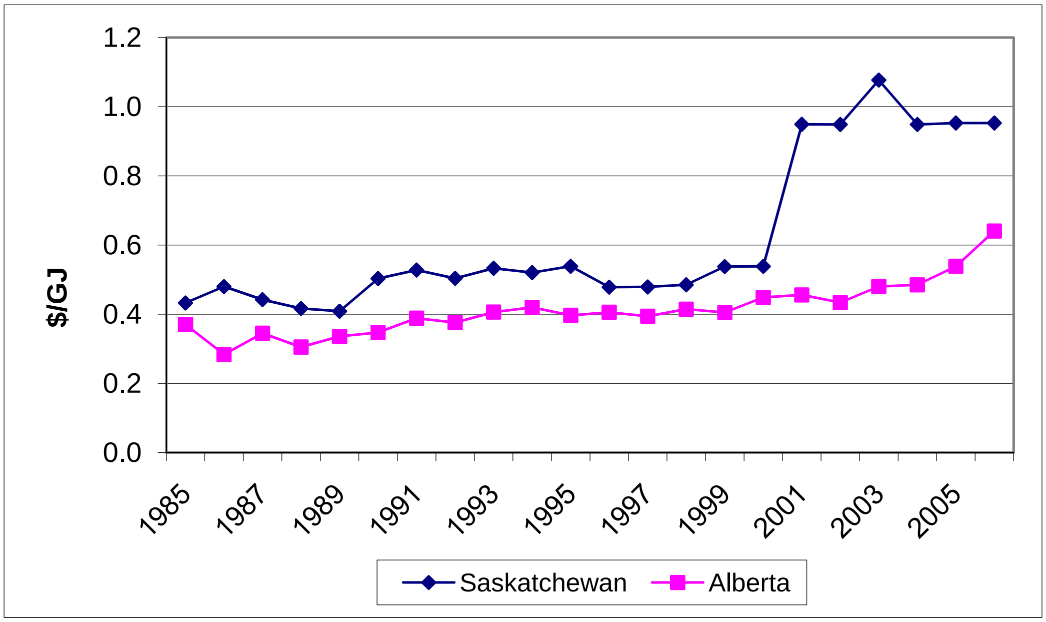


Source: CANSIM series V3840301 and V3840255. Real GDP is based on the expenditure method, and is computed at 1997 constant prices.

Apart from the period from 1993-1999, it is clear that growth in real GDP (and hence implied growth in electricity demand) is generally different in the two provinces, with growth generally higher in Alberta, especially in the post-restructuring period. These differences suggest that Saskatchewan data in the post-restructuring period may not be useful for making adjustments to the Alberta values for the endogenous variables in this period.

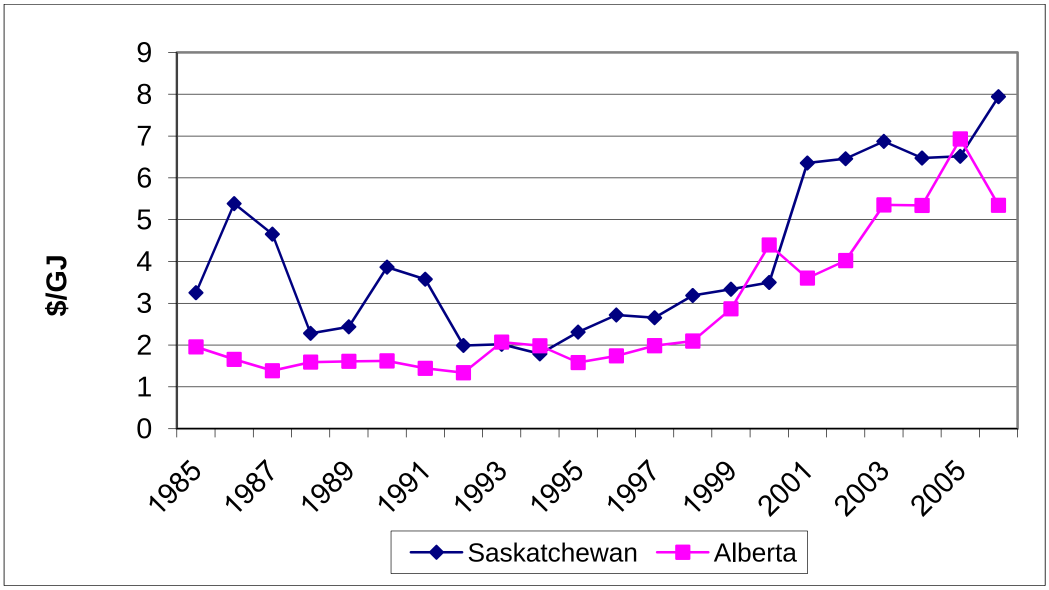
While the higher growth in electricity demand might be expected to contribute to higher electricity prices in Alberta, fuel prices appear to impact the electricity prices in the provinces in the reverse direction. Coal and natural gas prices ($/GJ) for 1985-2006 are depicted in Figures 5.2 and 5.3. These figures indicate that both coal and natural gas prices in Saskatchewan are more or less higher than those for Alberta throughout this period. However, the impact of higher coal and natural gas fuel prices on Saskatchewan electricity prices may be mitigated by the fact that 25% of Saskatchewan electricity generation capacity is based on hydro, which is generally a cheaper source of electricity generation than either coal- or natural gas-based generation. In short, based on growth in electricity demand and the share of hydro-based generation capacity it might be expected that Saskatchewan would have lower electricity prices than Alberta, but based on coal and natural gas fuel prices, the opposite might be expected. This indicates that despite the reasonably close similarity of the generation capacity share mix between the two provinces, the external environment, based on demand growth and fuel prices, is different in both Alberta and Saskatchewan, which would suggest not using Saskatchewan-based data to make adjustments to Alberta data in the post-restructuring period.

Figure 5.2: Coal Prices in Alberta and Saskatchewan



Source: Electricity Generation, Transmission and Distribution from Statistics Canada (CS57-202). Prior to 1997, the catalog series was called Electric Power Statistics Volume II Annual Statistics (CS57-202c).

Figure 5.3: Natural Gas Prices in Alberta and Saskatchewan

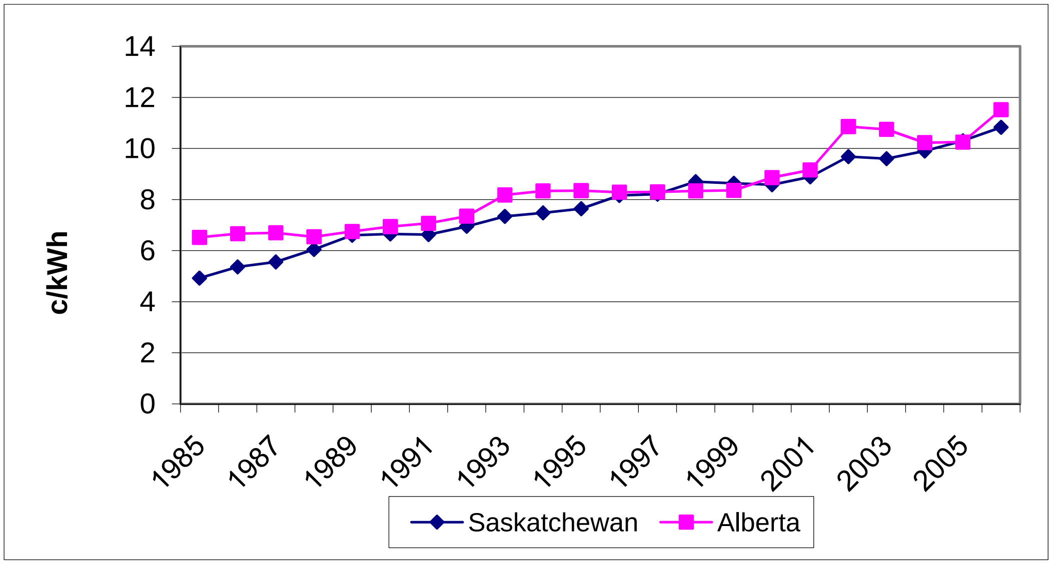


Source: Electricity Generation, Transmission and Distribution from Statistics Canada (CS57-202). Prior to 1997, the catalog series was called Electric Power Statistics Volume II Annual Statistics (CS57-202c).

Figures 5.4 and 5.5 display nominal and real electricity prices, respectively, for the domestic and farm sector for Alberta and Saskatchewan. For the pre-restructuring period, 1985-2000, it appears that Alberta electricity prices are more or less higher than those of Saskatchewan. This might be viewed as indicating that the lower electricity demand growth and the higher share of hydro-based generation in Saskatchewan have predominated over higher coal and natural gas fuel prices in keeping Saskatchewan electricity prices lower than those of Alberta. In the post-restructuring period, while nominal electricity prices in Alberta continue to remain generally higher than in Saskatchewan, in real terms Alberta electricity prices have been lower than those in Saskatchewan from 2004 to 2006.[2]

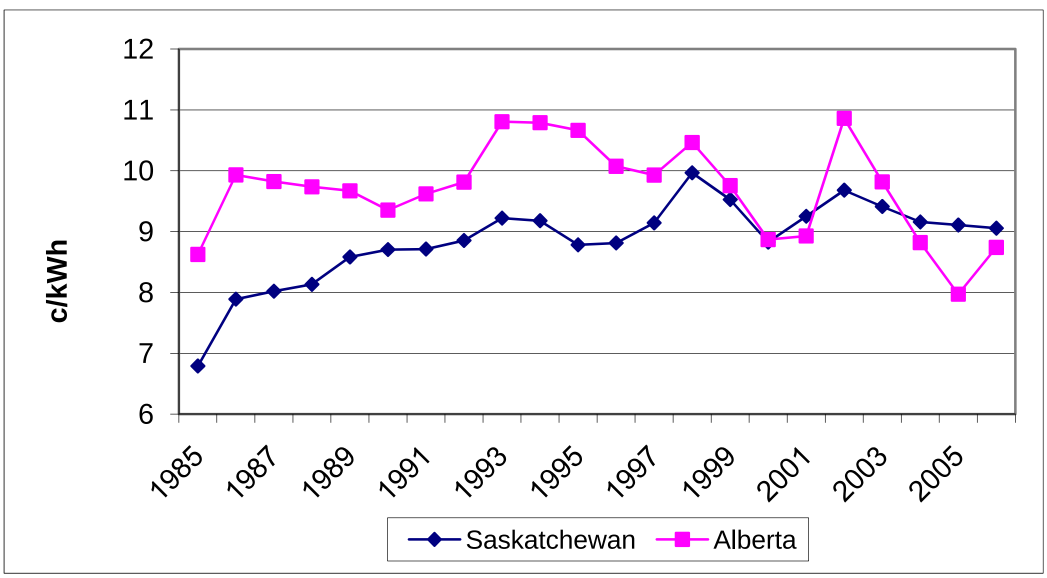
[2] Since residential electricity prices are being compared, it might make sense to use the CPI to convert the nominal electricity prices to real electricity prices. However, in order to remain consistent with the US data, where CPI is not available on a state wise basis, the Implicit Price Index was used to deflate the nominal Alberta electricity prices. When the Statistics Canada CPI series v41692327 and v41692191 were used to deflate the Alberta and Saskatchewan nominal electricity prices, respectively, Alberta real electricity prices for the 1985-2006 period were found to be higher than in Saskatchewan except for 1998, 1999, and 2005, when they were lower by 0.27, 0.24, and 0.16 cents per kWh, respectively.

Figure 5.4: Nominal Electricity Prices in Alberta and Saskatchewan



Source: Electricity Generation, Transmission and Distribution from Statistics Canada (CS57-202). Prior to 1997, the catalog series was called Electric Power Statistics Volume II Annual Statistics (CS57-202c).

Figure 5.5: Real Electricity Prices in Alberta and Saskatchewan (2002 base)



Source: Electricity Generation, Transmission and Distribution from Statistics Canada (CS57-202). Prior to 1997, the catalog series was called Electric Power Statistics Volume II Annual Statistics (CS57-202c). -Implicit Price Indices of GDP at market prices were obtained from CANSIM series V3840854 and V3840825.

To the extent that the impact of higher growth in electricity demand and the lower share of hydro-based generation dominate the impact of lower fuel prices in post-restructuring Alberta just as they appeared to do in pre-restructuring Alberta from 1985-2000, these lower Alberta real electricity prices in the post-restructuring period might be attributed to the restructuring that occurred. However, it is not clear, quantitatively, how much of the price differential between Saskatchewan and Alberta can be attributed to restructuring and how much is due to external factors. This is a particular concern when the decline in real electricity prices in Alberta from 1998 to 2000 is considered. While higher electricity demand growth and the relatively small amount of hydro-based generation may explain the higher levels of Alberta real electricity prices from 1998 to 2000, the declining trend in this time frame suggests that the impact of lower Alberta fuel prices was gradually reducing the impact of higher demand growth and the small share of hydro-based generation. Likewise, from 2000 to 2002, while coal- and natural-gas prices were still higher in Saskatchewan, it is not clear whether it is restructuring or higher growth in electricity demand that is driving relatively higher Alberta real electricity prices. In short it is very difficult to disentangle the impact of restructuring from the impact of external market conditions. In view of this difficulty, and since, in any event, electricity generation in Saskatchewan does not mimic the corresponding situation in Alberta closely, it does not appear that data from Saskatchewan are useful in helping to isolate the impact of restructuring on Alberta electricity prices from the impact of changes in external factors. As an alternative, we turn to a consideration of whether relevant data from various US jurisdictions might be helpful in this regard.

5.3 US Jurisdictions that Restructured their Electricity Markets

There appears to be no clear consensus on the restructuring status of the 51 US jurisdictions (50 states and the District of Columbia). For example, according to the document "US Restructuring at a Glance" from the National Energy Affordability and Accessibility Project",[3] as of 2003, Oregon and West Virginia had delayed or suspended electricity market restructuring whereas Wisconsin had pursued restructuring. However according to the 2006 "Restructuring Status of Electricity Markets" information from the Federal Energy Management program of the US DOE Energy Efficiency and Renewable Energy,[4] Oregon had implemented electricity market restructuring, West Virginia had merely been studying and observing it, and Wisconsin had not pursued any action. Therefore, prior to conducting any comparative analysis we begin by defining the restructuring status of the various US jurisdictions based on the most current and accurate information available. In contrast to earlier documentation which simply classified US jurisdictions as restructured or not, the 2006

[3] U.S. Restructuring at a Glance, http://www.neaap.ncat.org/restructuring/, National Energy Affordability and Accessibility Project , updated April 2003.

[4] http://www1.eere.energy.gov/femp/program/utility/utilityman_staterestruc.html, updated April 2006.

restructuring information classifies these jurisdictions according to six categories, as shown in Table 5.2.

Table 5.2: Restructuring Status of Electricity Markets as of 2006

Categories of Restructuring				
I	**II**	**III**	**IV**	**V**
Arizona (AZ)	Florida (FL)	Alabama (AL)	California (CA)	Montana (MT)
Connecticut (CT)	Hawaii (HI)	Alaska (AK)		Oklahoma (OK)
Delaware (DE)	Indiana (IN)	Colorado (CO)		
District of Columbia (DC)	Iowa (IA)	Georgia (GA)		
Illinois (IL)	Kentucky (KY)	Idaho (ID)		**VI**
Maine (ME)	Louisiana (LA)	Kansas (KS)		Arkansas (AR)
Maryland (MD)	Minnesota (MN)	North Carolina (NC)		Nevada (NV)
Massachusetts (MA)	Mississippi (MS)	North Dakota (ND)		New Mexico (NM)
Michigan (MI)	Missouri (MO)	South Carolina (SC)		
New Hampshire (NH)	Nebraska (NE)	South Dakota (SD)		
New Jersey (NJ)	Utah (UT)	Tennessee (TN)		
New York (NY)	Vermont (VT)	Wisconsin (WI)		
Ohio (OH)	Washington (WA)			
Oregon (OR)	West Virginia (WV)			
Pennsylvania (PA)	Wyoming (WY)			
Rhode Island (RI)				
Texas (TX)				
Virginia (VA)				

Definitions of Categories:	
Category I:	The transition period for phasing in restructuring has begun in these states, and they are currently implementing a competitive electric utility market for investor-owned utilities.
Category II:	These states are continuing to study and/or monitor restructuring investor-owned utilities, but are not currently pursuing further action.
Category III:	These states have completed studies investigating restructuring investor-owned utilities (power providers), and have decided not to pursue further action at this time.
Category IV:	These states have passed legislation suspending the restructuring process.
Category V:	These states have passed legislation delaying the restructuring process.
Category VI:	These states have passed legislation repealing the restructuring process.

Based on Table 5.2, it would appear that for the purposes of our analysis, Categories I, IV, V and VI can be considered as indicating US jurisdictions that restructured to varying extents, while US jurisdictions that fall under Categories II and III can be viewed as not having restructured. It would be important to underscore jurisdictions in Category I, as these jurisdictions are actively pursuing electricity market restructuring in contrast to those in Categories IV, V, and VI.

In order to confirm the proposed categorization of jurisdictions as restructured or not restructured, some additional analysis was undertaken. First, the 2003 "US Restructuring at a Glance" document, from the National Energy

Affordability and Accessibility Project, was revisited to focus on jurisdictions that had passed electricity market restructuring legislation in contrast to those that had instituted competitive electricity markets. On this basis, both the 2003 and the 2006 information sources become almost compatible. Specifically, according to the 2003 source, jurisdictions that had passed electricity market restructuring legislation include all those which – according to the 2006 source – fall under categories I, IV, V and VI in Table 5.2. West Virginia remains as an exception, however, since according to the 2003 source this state had passed electricity restructuring legislation but according to the 2006 source its electricity market remained non-restructured, and fell under Category II.

As a further check of the validity of the 2006 information source, it was compared with the EIA document "Status of State Electric Industry Restructuring Activity",[5] dated February 2003, which classifies US jurisdictions into four categories based on electricity market restructuring. In this document the state of restructuring is defined as "active", "delayed", "suspended" and "not active". These categories subsume the six categories from the 2006 source. The "active" restructuring category corresponds exactly to Category I from the 2006 information source, the "delayed" restructuring category subsumes Categories V and VI, the "suspended" restructuring category parallels Category V, and finally the "not active" restructuring category subsumes Categories II and III exactly.

This analysis suggests that the six classifications from the 2006 source have been appropriately grouped into two categories of restructured and not restructured. Therefore, for the purpose of our comparative analysis, 27 US jurisdictions will be considered as not having restructured their electricity markets, and the remaining 24 jurisdictions will be considered as those that have restructured, although only 18 of these are actively pursuing electricity market restructuring. The same classification of US jurisdictions is also used in Fagan (2005), which in turn is reviewed in the comprehensive study by Kwoka (2006).

According to the February 2003 document, active restructuring refers specifically to retail access, which is consistent with our focus on Alberta residential electricity prices. Thus, for our purposes restructuring would best be defined at the retail level and not just at the wholesale level, and while US jurisdictions in categories IV, V and VI are not actively pursuing retail market access, they will be included with those jurisdictions in Category I because, like California, they had implemented restructuring legislation and it is this criterion that has allowed the reconciliation of the various US data sources in terms of distinguishing between restructured and non-restructured jurisdictions. A second reason for this grouping is that since the impacts of restructuring are felt prior to the actual enactment of restructuring, the year of restructuring legislation will be used to distinguish between restructured and non-restructured jurisdictions so as to properly ascertain the impact of restructuring. Moreover, if the status of

[5] Status of State Electric Industry Restructuring Activity, EIA, http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf, February 2003

restructuring were defined by the actual year of restructuring as opposed to the year of passing restructuring legislation, then fewer data points post restructuring are left for comparison purposes. Finally, while studies like Fagan (2005) concentrate on the long run impact of restructuring and hence exclude the six states in categories IV, V and VI from the list of restructured states, we are also interested in the short run impacts of restructuring in order to study phenomena like the skyrocketing Alberta electricity prices in 2001, immediately after restructuring.

Table 5.3 defines the 51 US jurisdictions according to their census division and also on the basis of their restructuring status. The US is divided into nine Census Divisions based on data presentation and not necessarily due to geography, although jurisdictions in a census division are usually geographically related. The data on US jurisdictions are presented in the context of their presence in a census division given issues concerning data on inter-connections between the electricity markets of contiguous US jurisdictions.[6] The 24 jurisdictions which are listed in **bold** in Table 5.3 are those that have restructured their electricity markets. This indicates that while restructured jurisdictions are geographically proximate, as in the cases of Middle Atlantic and New England states, alluding to the importance of interconnectivity, the mix of restructured and non-restructured jurisdictions in other census divisions makes for an interesting separate study as to why they made different decisions concerning electricity market restructuring. Note that in the absence of data on interconnectivity, US jurisdictions cannot be compared with Alberta based on the exact MW of interconnection between contiguous jurisdictions.

[6] Data on interconnectivity of electricity markets from the North American Electric Reliability Council (*NERC*) was not accessible. In any event, US jurisdictions could not be defined based on their belonging to a NERC regional council, because of changes in the composition of states in a NERC council due to changed interconnectivity status. The regional councils themselves seem to have been redefined with time.

Table 5.3: US Restructuring Status according to Census Division

New England	Middle Atlantic	East North Central	West North Central	South Atlantic
Connecticut **Maine** **Massachusetts** **New Hampshire** **Rhode Island** Vermont	**New Jersey** **New York** **Pennsylvania**	**Illinois** **Michigan** **Ohio** Indiana Wisconsin	Iowa Kansas Minnesota Missouri Nebraska North Dakota South Dakota	**Delaware** **District of Columbia** Florida Georgia **Maryland** North Carolina South Carolina **Virginia** West Virginia
East South Central	**West South Central**	**Mountain**	**Pacific**	
Alabama Kentucky Mississippi Tennessee	**Arkansas** Louisiana **Oklahoma** **Texas**	**Arizona** Colorado Idaho **Montana** **Nevada** **New Mexico** Utah Wyoming	Alaska **California** Hawaii **Oregon** Washington	

Table 5.4, extracted from the February 2003 EIA document, indicates the year in which the restructuring legislation was passed in the various US jurisdictions, and the expected year of retail access for all customers.[7] In Alberta, the restructuring legislation was passed in 1996 while retail access began in 2001. However, to allow for the possibility of changed (anticipatory) behaviour by industry players, possibly resulting from changes in expectations once the restructuring legislation was enacted, in the analysis for Alberta in the previous chapter the pre-restructuring and post-restructuring period were differentiated by the year of the legislation. This year pre-dates the implementation of any aspects of the restructuring, including the retail access date.

For the purposes of our analysis, the pre- and post-restructuring periods for the 51 US jurisdictions will also be defined by the year of the restructuring legislation enactment or the regulatory order as opposed to the year of full retail access. This is consistent with the analysis for Alberta, but is also adopted for operational purposes since for some US jurisdictions retail access was delayed beyond 2004, which provides few if any observations that can be used to study the impact of restructuring, while for several jurisdictions the dates for retail access were changed on several occasions.

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[7] The EIA document also lists the respective years of access separately for residential and commercial / industrial customers, but this detail is omitted from Table 5.4 as this information is not pertinent to our analysis.

US jurisdictions were classified into those that restructured their electricity markets and those that did not in order to implement the analysis required for the two approaches outlined in Section 5.1. However, determination of a non-restructured and a restructured jurisdiction that mimic Alberta, and of pairs of jurisdictions – one restructured and one not – that otherwise mimic each other, will have to be guided by the availability of the data for all 51 US jurisdictions on the explanatory variables that are included in the regression model. Data for the US jurisdictions are described in the following section.

Table 5.4: Dates of Restructuring Legislation and Retail Access for US Jurisdictions

US Jurisdiction	Legislation Enactment / Regulator Order	Full Retail Access
Category I		
Arizona	1998	2001
Connecticut	1998	2000
Delaware	1999	2001
Columbia District of	2000	2001
Illinois	1997	2002
Maine	1997	2000
Maryland	1999	2002
Massachusetts	1997	1998
Michigan	2000	2002
New Hampshire	1996	2001
New Jersey	1999	1999
New York	1996	2001
Ohio	1999	2001
Oregon	1999	2002
Pennsylvania	1996	2000
Island Rhode	1996	1998
Texas	1999	2002
Virginia	1999	2004
Categories IV, V and VI		
Arkansas	2001	2005
Montana	1997	2004
Nevada	1997	2002
New Mexico	1999	2008
Oklahoma	1997	delayed indefinitely
California	1996	1998

Note: Restructuring categories are those listed in Table 5.2. Restructuring is active in those jurisdictions included in Category I, but has been suspended, delayed or repealed in jurisdictions in Categories IV, V, and VI.

5.4 Data for US Jurisdictions

As described in Section 5.1, the explanatory variables in the model of the determinants of electricity price may be categorized in terms of whether they are endogenous or exogenous variables. Variables like generation, capacity, utilization ratios, and heat rates are classified as endogenous variables given the potential impact of restructuring on generation mix and efficiency, whereas variables like coal and natural gas prices, HDD and economic growth are treated as exogenous. Data on the exogenous variables as well as on the pre-restructuring values of the endogenous variables can be compared across US jurisdictions to attempt to identify pairs of jurisdictions – one restructured and one not – that are similar on the basis of these variables. As described later, such comparisons can be used to help quantitatively identify the impact of restructuring on the post-restructuring values of the endogenous variables in restructured jurisdictions.

Data on electricity prices, natural gas prices, coal prices, generation capacity, generation and fuel consumption[8] for all 51 jurisdictions were obtained from the Energy Information Administration *EIA*, US DOE website.[9] Economic growth was computed using data on real GDP available for the US jurisdictions from 1990 to 2004 from the Bureau of Economic Analysis *BEA* of the US Department of Commerce.[10] Data availability issues preclude any comparative analysis for the user cost of capital. Details are provided below.

5.4.1 Electricity Prices

Electricity Prices for the 51 US jurisdictions were obtained from the web link http://www.eia.doe.gov/cneaf/electricity/epa/average_price_state.xls at the Energy Information Administration *EIA*, US DOE website. These prices, in units of cents/kWh were available in four categories according to the type of electricity providers – the total electric industry, full-service providers, energy-only providers and delivery-only service. The prices were further subdivided according to five categories, including the three customer classes – residential, commercial and industrial – for each of the previous four provider categories.

According to the glossary on the EIA website,[11] full service providers are utilities, municipalities, cooperatives and others who provide both electricity and the transmission services necessary to deliver it to end-use customers; energy-only providers are power marketers or other electricity vendors who provide an unbundled service and bill for only the energy component of the electricity consumed by the end-use customer; and delivery-only providers are owners and/or operators of transmission and distribution system equipment who provide billing and related energy services for the transmission and delivery of electricity.

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[8] Heat rates are based on fuel consumption and generation.
[9] http://www.eia.doe.gov (last accessed: July, 2011).
[10] http://bea.gov/regional/gsp (last accessed: July, 2011).
[11] http://www.eia.doe.gov/cneaf/electricity/page/glossary.html (last accessed: July, 2011).

The relevant categories for our purposes are the electricity prices categorized under total electric industry and full-service providers, because these incorporate electricity utilities. Since our emphasis is on studying the impact of electricity prices on residential customers, we will consider the residential electricity prices for both categories. The average yearly difference from 1990 to 2004 between residential electricity prices for the total electric industry and for full-service providers for the 51 US jurisdictions is only 0.01 cents/kWh relative to means of 8.35 and 8.34 cents/kWh for the respective electricity prices, and since the two sets of prices are mostly the same, we can use either price for our analysis. However, since the Alberta electricity prices were not separable between electricity utilities and industrial establishments, we will use the US residential electricity prices based on the total electric industry as opposed to using the residential prices based on full-service providers, which may not include industrial establishments.

5.4.2 Electricity Generation Capacity and Generation

Generation capacity data for the 51 US jurisdictions were extracted from http://www.eia.doe.gov/cneaf/electricity/epa/existing_capacity_state.xls, a web link at the Energy Information Administration *EIA*, US DOE web site. These data, in units of MW, are available on an annual basis for two categories – name plate capacity and summer capacity – and for the 1990-2004 period. Generator nameplate capacity is defined as the maximum rated output of a generator under specific conditions designated by the manufacturer, and is usually indicated on a nameplate physically attached to the generator.

These capacity data are available for Electric Utilities, Independent Power Producers (IPP), and the Total Electric Power Industry, and are further classified by energy source, which includes but is not limited to coal, hydro-electric, natural gas, and nuclear based generation capacity. Capacity data for coal and natural gas for electric utilities are relevant since the Alberta generation capacity data are available for electric utilities. However, hydro- and nuclear-based capacities will also be considered at the outset, as they form a large share of capacity for some of the US jurisdictions.

Data on electricity generation in units of MWh were extracted from the web link http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls from the EIA, DOE website. These generation data are available from 1990–2004 for Electric Utilities, Independent Power Producers (IPP), and the Total Electric Power Industry. and are further classified by energy source, which includes but is not limited to coal, hydro-electric, natural gas, and nuclear-based generation. Both capacity and generation data for the US jurisdictions will be considered for electric utilities because generation and capacity data for Alberta are available for utilities.

The data on capacity and generation classified by the type of fuel – coal, gas, hydro and nuclear – are converted to the percentage of total capacity and the percentage of total generation associated with each fuel type. This conversion to percentages provides a convenient format for observing any substitutions within the generation and capacity mix. Note, however, that while the capacity and generation data for both Alberta and the US jurisdictions pertain to total utilities, due to availability and consistency issues the data for electricity prices refer to the total industry. This data inconsistency is not viewed as a serious issue since, as noted above, the average differential between electricity prices for US jurisdictions for the total electric industry and for full service providers is 0.01 cents/kWh across all 51 jurisdictions from 1990 to 2004. Likewise, since the principal utilities generated the major proportion of electricity, even in Alberta the electricity prices for the total industry and utilities combined would perhaps be virtually indistinguishable from the electricity prices for total utilities. Thus, the inconsistency in the data does not seem to have any major implications for the analysis.

5.4.3 Capacity Utilization and Heat Rates

Capacity Utilization was calculated as the ratio of generation to capacity, and is used as a measure of tightness in electricity supply. The exact calculation entails converting capacity data in units of MW to units of MWh, so that the numerator and denominator are expressed in the same units. This is achieved by multiplying capacity data by 8760, that is, the total number of hours in a year, to reflect the annual frequency of the capacity data. This calculation yields capacity utilization, also known as the capacity factor (DeWinkel, 2011), and was computed separately for coal- and gas-based capacity utilization.[12]

Heat Rates – a measure of thermal efficiency – indicate the amount of fuel energy required by a power plant to produce one kilowatt-hour of electrical output. They are computed separately for coal- and natural gas-based generation by dividing the heat content of the fuel used in generation by total generation from the specific fuel. For coal-based generation, coal consumption in units of short tons is converted to GJ units by multiplying these values by the heat content of each short ton.

[12] The formula used to compute capacity utilization ratios is exactly the same as that used for obtaining the capacity factor, the ratio of annual net generation (MWh) to the product of Nameplate capacity (MW) and 8760 (hrs in a year). This formula has also been used by Douglas (2006), who studies the utilization of coal-fired power plants in the US. The load factor has been defined similarly to the capacity factor in DiPietro and Krulla (2001), although instead of 8,760, those authors multiply nameplate capacity by operating hours during the year, where operating hours do not include the time the unit is shut down for maintenance or other reasons. Here, in the calculation of utilization ratios, the maximum available 8,760 hours in a year is used, so that no adjustment is made for the time that generators are taken out of service for maintenance, etc. Such an adjustment would require detailed plant level data that are not available for the sample period. To the extent that planned outages do not change over time, the results obtained here would not be expected to be significantly affected, although this could be an interesting complexity to address in future research.

Data on fuel consumption for both coal and natural gas were extracted from http://www.eia.doe.gov/cneaf/electricity/epa/consumption_state.xls,a web link to the EIA-DOE website. These data are available from 1990–2004 for Electric Utilities, Independent Power Producers (IPP) and the Total Electric Power Industry for coal in units of short tons and for natural gas in units of MCF. As with the data on capacity and generation, for consistency purposes data on fuel consumption will pertain to electric utilities.

Total fuel consumption was computed as the sum of coal consumption and natural gas consumption, which were first converted from units of short tons and MCF to GJ equivalents using the following conversion factors.

1 MCF = 28.317 cubic metres
1 GJ = 26.8 cubic metres
1 metric tonne = 1.1023 short tons
1 metric tonne = 24.137 GJ

Subsequently, coal and gas consumption were converted to percentages of total fuel consumption to clearly discern any shift in the fuel consumption mix.

The data on approximate heat content of coal and coal coke for the electric powers sector in units of millions Btu per short ton from 1990–2004 were extracted from the web link http://www.eia.doe.gov/emeu/aer/txt/stb1305.xls from the EIA, DOE website. These heat content data in units of millions Btu / short ton content were converted to units of GJ / short ton, using the following standard conversion:

1 GJ = 947,817 Btu

The data on approximate heat content for natural gas for the electric power sector in units of Btu per cubic foot from 1990–2004 were extracted from the web link http://www.eia.doe.gov/emeu/aer/txt/stb1304.xls from the EIA, DOE website. These data were converted to units of GJ per cubic metre, using the following standard conversions:

1 MCF = 28.317 cubic metres
1 GJ = 947,817 Btu

Data on heat content of coal and gas are available for the US as a whole and for electric utilities only through 1988; beginning in 1989, data pertain to electric utilities and independent power producers. In absence of data for individual states, these heat contents are used to convert the data on coal and natural gas consumption in their natural units to GJ equivalents. While it would have been easier to simply use standard conversions to convert coal and natural gas consumption data to GJ equivalents, these conversions do not take into account the type of coal or natural gas used specifically in electricity generation. Given the energy content of coal and natural gas and the coal- and natural gas-based generation data, coal- and natural gas-based heat rates were computed in common units of GJ/GWh.

5.4.4 Fuel Prices

Data for the natural gas electric power price (the price of natural gas sold to electric power consumers) for 1997 – 2004 were obtained for all 51 jurisdictions from the EIA website
http://tonto.eia.doe.gov/dnav/ng/xls/ng_sum_lsum_a_EPG0_PEU_DMcf_a.xls.
Data for the average price of natural gas delivered to US utilities by state from 1967–2000 were extracted from the EIA website from the web link
http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/historical_natural_gas_annual/hnga.html. For the overlap years, 1997 to 2000, these two sources have identical values, indicating that they can be combined together to form a price data series from 1967–2004. Another data set was available from the latter web link as "Prices of natural gas deliveries to electric utilities by state from 1993–1998". This data set, which distinguished between firm and interruptible supplies, was not utilized as it does not match with the 1997–2004 data set and also is only available over a much shorter period.

The natural gas price data from 1967–2004 are in units of \$ / thousand cubic feet, which is converted to \$ / GJ using the following standard conversion factors:

1 MCF = 28.317 cubic metres
1 GJ = 26.8 cubic metres

Data for the average price of coal delivered to end use sector by state in units of nominal \$/ short tons are available from 1985–2004 from the EIA website,
http://www.eia.doe.gov/cneaf/coal/page/acr/backissues.html. These data were converted to units of \$ / GJ using the following standard conversion factors:

1 ton = 1 short ton
1 metric tons = 1.1023 tons
1 metric ton = 24.137 GJ

5.4.5 Real GDP

The values of the real GDP for each US state from 1990–2005 are available in millions of chained 2000 dollars. However, the data from 1990–1997 are based on the U.S. Standard Industrial Classification System (*SIC*), whereas data for 1997–2005 are based on the North American Industry Classification System (*NAICS*). A cautionary note at the BEA website indicates:[13]

> *There is a discontinuity in the GDP by state time series at 1997, where the data change from SIC industry definitions to NAICS industry definitions. This discontinuity results from many sources, including differences in source data and different estimation methodologies. In addition, the NAICS-based GDP by state estimates are consistent with U.S. gross domestic product (GDP) while the SIC-based GDP by state estimates are consistent with U.S. gross domestic income (GDI). This data discontinuity may affect both the levels and the growth rates of the GDP by state estimates. Users of the GDP by state estimates are strongly cautioned against appending the two data series in an attempt to construct a single time series of GDP by state estimates for 1963 to 2006.*

While it is not appropriate to splice the two real GDP series, given that the purpose is to compare across US jurisdictions, as opposed to analyzing the growth in GDP through time, the issue of splicing the real GDP for the two time periods together does not appear to impact the comparative analysis significantly. When two US jurisdictions – one restructured and one not – are compared on the basis of differences in their real GDP growth rates each year for 1990 – 2005, given that the data for both jurisdictions are affected by the same structural break in 1997 due to a different way of data reporting, the comparison between the two jurisdictions will not be affected. Had the data for the restructured and non-restructured jurisdictions been affected by different factors then the comparison based on differences would have been inappropriate.

5.4.6 Real Wages

Annual wage per worker was also constructed from the data on wages and number of jobs available at the BEA website.[14] Private wage and salary disbursements for electric, gas and sanitary services are available in thousands of dollars from 1960–2000 under Code 570. Private wage and salary disbursements for utilities are available in thousands of dollars from 2001–2005 under Code 300. Private wage and salary employment data for electric, gas and sanitary services are available in units of number of jobs from 1969–2000 under Code 570. Private wage and salary employment for utilities is available in units of number of jobs from 2001–2005 under Code 300.

The data on both wages and number of jobs as indicated above are available in two components, from 1960- or1969–2000 and then from 2001–2005. This distinction arises for the same reason as in the case of data on state GDP, that

[13] http://bea.gov/regional/gsp , (last accessed: July, 2011).
[14] http://bea.gov/iTable/index_nipa.cfm (last accessed: July, 2011).

is, the later data sets are based on NAICS, whereas the earlier ones are based on the SIC system. Nonetheless, as in the case of state GDP, since our purpose is to compare jurisdictions and since a common factor affects the data for all jurisdictions, the issue of appending the data sets is not expected to significantly affect our analysis. Annual wage per worker is computed by dividing wages by number of jobs for 1969–2005.

5.4.7 Heating Degree Days

Data on heating degree days, *HDD*, used to capture aspects of weather, were extracted from the National Climactic Data Centre of the US Department of Commerce[15] for 1993 to 2005. Monthly heating degree day totals for each state are computed by weighting the division HDD values with the percentage of the state population residing in that division, using information from the 1990 US census. This weighting of divisional HDDs ensures that divisions with larger populations are given greater weight in the overall calculation of HDD. The HDD data are weighted by 1990 census data from January 1993 to June 2001, whereas from July 2001 to December 2005, the weights are based on 2000 census data. The base temperature used in the calculations is 65ºF, which is the same as the 18ºC benchmark used in the case of the Alberta HDD data.

It was noted in Section 4.3.7 in Chapter 4 that in the context of Alberta the focus was on HDD rather than CDD (cooling degree days), since the latter are relatively low in Alberta, so that there is relatively low demand for electricity for space cooling purposes in the residential sector. However, to the extent that space cooling considerations might be more relevant for US jurisdictions than space heating, CDD data might be more appropriate in terms of reflecting electricity demand. An alternative would be to focus on some weighted average of HDD and CDD for US jurisdictions, although increased HDD might reflect increased natural gas rather than electricity usage – to the extent that natural gas is used for space heating – whereas increased CDD would reflect increased electricity usage for air conditioning/cooling. It is not clear what weights to use to combine US HDD and CDD data for the purpose of making comparisons with Alberta, and if relative shares based on Alberta data are used to weight US HDD and CDD data, the situation would be equivalent to just using HDD data in view of the relative unimportance of CDDs in Alberta. Here this complexity is ignored, and US jurisdictions are compared on the basis of HDDs, as the eventual objective is to determine jurisdictions that are similar to the Alberta electricity environment and, as noted before, in the Alberta context HDD retain much greater importance.[16]

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[15] http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html#52updates (last accessed: July, 2011).

[16] In any event, as will be noted later in Sections 5.7 and 5.8, the jurisdictions will be matched on the basis of three composite variables that do not involve HDDs, so that any analysis conducted on the basis of CDDs will not influence the results. A possibility for future work is to examine ways that information from CDDs or a weighted average of HDD and CDDs could be incorporated in the analysis.

5.5. Analysis of the US Data

The data described in the previous section will be used subsequently to identify restructured and non-restructured jurisdictions that are similar to each other, and to Alberta, in terms of various aspects of electricity production. The objective of such analysis is to determine the likely effects of restructuring on endogenous variables like capacity, generation, utilization and heat rates, and to incorporate these effects when making counterfactual forecasts of electricity prices in the post-restructuring period in Alberta.

However, before beginning the task of matching jurisdictions, we first analyze the US data to determine whether there are any significant differences between jurisdictions that restructured their electricity markets and those that did not. By comparing US jurisdictions that restructured and those that did not, and separately considering those jurisdictions where the electricity price increased after restructuring and those where it did not, the initial focus is on determining whether there are any apparent effects of restructuring on electricity prices, and whether some or all of the explanatory factors included in our model of electricity prices appear to be associated with these differences. The primary motivation for this analysis is to determine whether particular attention should be paid to certain of these variables when making adjustments to the Alberta values in the post-restructuring period.

We begin by examining electricity prices, and use the difference of means test to determine whether there are any statistically significant differences between the electricity prices in the two kinds of jurisdictions.[17] This test is not applied to the explanatory variables, however, since the primary purpose of examining those variables is to determine how their magnitudes changed between the pre-restructuring and the post-restructuring periods, and whether and to what extent this differs in the two types of jurisdictions. Potentially, such differences will be used subsequently to modify the values of the explanatory variables for Alberta in the post-restructuring period.

5.5.1 Difference of Means Test[18]

A difference of means test can be used to test for difference between the means of two groups of data. In our context it can be used to determine whether there is any significant change in electricity prices and other variables after restructuring. Three assumptions underlie the use of the particular version of the test that has been selected:

[17] In our analysis, observations from different jurisdictions are treated as being independent. However, this may not be the case, since various jurisdictions may be members of the same power pool, such as the New England Power Pool (NE POOL).

[18] Online Statistics: An Interactive Multimedia Course of Study, http://onlinestatbook.com/chapter10/difference_means.html (last accessed July 2011) and Neustadl, A. (2007), Difference of two means test Handout, http://www.bsos.umd.edu/socy/alan/handouts/diff_of_two_means.pdf (last accessed: July, 2011)

1) The two populations from which the data are extracted have the same variance.

2) The two populations are normally distributed.

3) Each value is sampled independently from each other value.

Given the fact that electricity prices have become quite volatile in the post restructuring period, it is likely that the first assumption is violated. However, the volatility would be muted because we are using annual prices, and in any event, violations of the first two assumptions are not considered important in the context of the test, although it is important not to violate Assumption 3.[19] Nevertheless, to allow for this possibility, two forms of the test will be conducted, first based on the assumption of equal variances for the two populations, and then with this assumption relaxed. In our case the third of the three assumptions might be expected to hold because we are using annual prices. Hourly prices may be related owing to the events that extend beyond an hour, daily consumption patterns, the presence of any tacit collusion, etc. However, even in the case of hourly prices, demand responsiveness may serve to offset some of these effects, and hence weaken any clear relationship between hourly prices.

The difference of means test used is a simple t test that tests for the difference in means between two groups of data. The t test statistic, which has a t distribution with a specified number of degrees of freedom (df), is defined by the usual formula:

(5.1) t = (test value – hypothesized value) / estimated standard error of the test value

The test value is equal to the difference between the sample means of the two groups (M_2-M_1), and the hypothesized value is zero, since the null hypothesis is that there is no difference between these two means. The estimated standard error is computed according to the following formulas that differ according to whether the two populations are assumed to have equal variances (Case I) or unequal variances (Case II). Here n_1 indicates the number of observations from the first data source and n_2 denotes the number of observations from the second data source.

(5.2a) $$s = \sqrt{\frac{n_1 s_1^2 + n_2 s_2^2}{n_1 + n_2 - 2}} \times \sqrt{\frac{n_1 + n_2}{n_1 n_2}}$$ for equal variances (Case I)

(5.2b) $$s = \sqrt{\frac{S_1^2}{n_1 - 1} + \frac{S_2^2}{n_2 - 1}}$$ for unequal variances (Case II)

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[19] See: Online Statistics: An Interactive Multimedia Course of Study, http://onlinestatbook.com/chapter10/difference_means.html (last accessed July 2011).

The degrees of freedom for the test also differ for the two cases, and are given by equations (5.3a) and (5.3b):

(5.3a) $$df = (n_1 + n_2 - 2)$$ for equal variances (Case I), and

(5.3b) $$df = \left(\frac{\left(\frac{s_1^2}{n_1 - 1} + \frac{s_2^2}{n_2 - 1} \right)^2}{\left(\frac{s_1^2}{n_1 - 1} \right)^2 \left(\frac{1}{n_1 + 1} \right) + \left(\frac{s_2^2}{n_2 - 1} \right)^2 \left(\frac{1}{n_2 + 1} \right)} - 2 \right)$$

for unequal variances (Case II)

5.5.2 Analysis of US Electricity Prices

Residential electricity prices for the total electric industry are available in units of cents/kWh from 1990 – 2004 for the 51 US jurisdictions. Each of the 24 US jurisdictions that were categorized as having restructured their electricity markets has different dates when the legislation on electricity market restructuring was passed and when retail access was implemented for all customers.[20] To facilitate comparisons of electricity prices between the group of jurisdictions that restructured their electricity markets and the group that did not, it is helpful to define a common year to distinguish the pre- and post-restructuring periods. Since the first year that any jurisdiction passed restructuring legislation was 1996, for our purposes here we will define the pre-restructuring period as 1990-1995 (6 observations per jurisdiction) and the post restructuring period as 1996-2004 (9 observations per jurisdiction). The fact that this definition is not necessarily appropriate for each jurisdiction is an obvious drawback of this approach, so that the results are suggestive rather than definitive, but in subsequent analysis the actual dates of restructuring for each jurisdiction are utilized.

For the purpose of comparing electricity prices between the restructured and non-restructured US jurisdictions, the retail access date is not used to distinguish between the pre- and post-restructuring periods simply because for some states retail access was curtailed or delayed beyond 2004, and also because the effect of forthcoming retail access may be reflected in electricity prices before any actual implementation. This latter reason was also considered in distinguishing the pre- and post-restructuring periods by the year 1996, even though only 5 of the 24 jurisdictions had passed electricity market legislation by 1996.

As shown in the first row of Table 5.5, in the pre-restructuring period, the US as a whole had an average residential electricity price of 8.20 cents/kWh for

[20] Status of State Electric Industry Restructuring Activity, EIA, http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf (last accessed: July, 2011).

1990-1995.[21] The US electricity price is close to the average electricity price for all 51 jurisdictions from 1990 -1995, that is, 8.08 cents/kWh.[22] In the same period, the average residential electricity price for the 27 jurisdictions that did not restructure their electricity markets was 7.23 cents/kWh and for the 24 jurisdictions that did restructure, the average price was 9.02 cents/kWh. This indicates that jurisdictions that pursued electricity market restructuring tended to have higher average residential electricity prices than those that did not pursue restructuring.

In the post restructuring period from 1996 to 2004, the average electricity prices for all 51 jurisdictions, the 24 restructured jurisdictions and the 27 non-restructured jurisdictions are 8.53, 9.41, and 7.75 cents/kWh respectively. This indicates that post-restructuring, average residential electricity prices increased for both the restructured and the non-restructured US jurisdictions. On closer examination, the rate of change in the average residential electricity prices between the pre- and post-restructuring periods is 7.13% for non-restructured jurisdictions, 5.53% for all 51 jurisdictions and 4.25% for jurisdictions that restructured their electricity markets. This indicates, on a preliminary level, that average residential electricity prices have increased more for jurisdictions that did not restructure compared to those that did restructure.

These findings suggest that residential electricity prices were likely to have increased in the post-restructuring period (as defined here) even had restructuring not occurred. Our analysis can be made more robust by applying the difference of means test to electricity prices from the pre- and post-restructuring periods separately for the jurisdictions that restructured and those that did not. In our context, this test can be conducted in two different ways. First, electricity prices in each year for each jurisdiction can be used to construct the test statistic (METHOD 1). Second, average electricity prices over the relevant period (pre-restructuring or post-restructuring) for each jurisdiction can be used (METHOD 2). The t statistics for the difference of means tests using both these methods are provided in Table 5.5 for the restructured states, non-restructured states, all the 51 states and for the US as a whole.

[21] In order to be consistent with the previous modelling of nominal electricity prices for Alberta, the analysis here is based on using nominal rather than real electricity prices to compare restructured and non-restructured US jurisdictions. Moreover, data for CPI or the GDP deflator are available on a regional basis but not by individual jurisdiction.
[22] The EIA provides data for each of the 51 jurisdictions as well as for the US overall. See http://www.eia.doe.gov/cneaf/electricity/epa/average_price_state.xls (last accessed: July, 2011).

Table 5.5: Significance of Change in Average Residential Electricity Price between the Pre- and Post-Restructuring Periods

Average residential electricity price							
	Restructured Jurisdictions		Non-restructured Jurisdictions		US	All 51 Jurisdictions	
Pre-restructuring period 1990-1995	9.02		7.23		8.20	8.08	
Post-restructuring period 1996-2004	9.41		7.75		8.47	8.53	
rate of change	4.25%		7.13%		3.31%	5.53%	
METHOD 1	**Case I**	**Case II**	**Case I**	**Case II**	**Case I***	**Case I**	**Case II**
n_1	144	144	162	162	6	306	306
n_2	216	216	243	243	9	459	459
df (degrees of freedom)	355	316	403	403	13	763	712
s_1^2	4.29	4.29	2.42	2.42	0.05	4.09	4.09
s_2^2	4.60	4.60	4.75	4.75	0.07	5.36	5.36
s	0.23	0.23	0.20	0.19	0.13	0.16	0.16
M_2-M_1	0.38	0.38	0.52	0.52	0.27	0.45	0.45
t	1.67	1.69	2.59**	2.77**	2.13	2.79**	2.86**
t* (α=0.01)	2.59	2.59	2.59	2.59	3.01	2.58	2.58
METHOD 2	**Case I**	**Case II**	**Case I**	**Case II**	**N/A**	**Case I**	**Case II**
n_1	24	24	27	27	1	51	51
n_2	24	24	27	27	1	51	51
df	46	43	52	49	0	100	100
s_1^2	4.17	4.17	2.42	2.42		3.99	3.99
s_2^2	4.47	4.47	4.73	4.73		5.21	5.21
s	0.61	0.56	0.51	0.52		0.43	0.43
M_2-M_1	0.38	0.38	0.52	0.52	0.27	0.45	0.45
t	0.63	0.69	0.98	0.98		1.06	1.06
t* (α=0.01)	2.69	2.70	2.67	2.68		2.63	2.63

** Significant at 1% level of significance; *Case II results for US as a whole, while not reported, are very similar.

It is clear from Table 5.5, that Method 1 seems more appropriate not only because of greater number of observations available with this method, but also because the averaging inherent in Method 2 eliminates much of the variation between individual jurisdictions and years, and because the test cannot be computed for the US using Method 2. The variances of the pre- and post-restructuring periods – s_1^2 and s_2^2 – indicate that the volatility of electricity prices increased in the post-restructuring period. An interesting finding is that in the pre-restructuring period the volatility of restructured jurisdictions was about twice as high as the volatility of the non-restructured jurisdictions. However, the volatility in non-restructured jurisdictions increased by 95.54%, whereas the volatility in restructured jurisdictions increased by only 7.23% in the post-restructuring period. Finally, compared to data from all 51 jurisdictions, the US-as-a-whole data do not seem suitable for our analysis as they are devoid of the volatility inherent in both the restructured and the non-restructured jurisdictions.

The results using Method 1 in Table 5.5 indicate that the difference between the pre- and post-restructuring electricity prices for all 51 jurisdictions is significant, and the same result also holds for non-restructured jurisdictions. For restructured jurisdictions, the change in the electricity prices between the two periods is statistically insignificant. However, in all cases the test statistics are positive, which indicates that prices were increasing in both types of jurisdictions irrespective of restructuring.

The significance of the difference between the electricity prices in the pre- and post-restructuring periods for non-restructured jurisdictions indicates that some other factors are responsible for the price increases in those jurisdictions. The statistical insignificance result for restructured jurisdictions tends to indicate that prices were merely following their usual upward trend in those jurisdictions. This suggests that rather than claiming that restructuring was responsible for these price changes, it is necessary to look to other explanations for the price increases in these jurisdictions in the post-restructuring period, such as increases in fuel costs. The similarity of the results for Case I and Case II indicate that the results do not depend on whether or not the assumption of equal variances is imposed when conducting the test.

The same difference-in-means testing framework can also be used to test whether electricity prices were significantly different between the two types of jurisdictions in both the pre- and post-restructuring periods. Table 5.6 indicates that while the electricity prices in both types of jurisdictions are different in both periods, the difference is also statistically significant in both periods (higher in both cases in the jurisdictions that restructured) even at the 1% level of significance. Again, the results do not depend on whether the assumption of equal (Case I) or unequal variances (Case II) is used for conducting the test.

Table 5.6: Significance of Difference in Average Residential Electricity Price between the Two Types of Jurisdictions in Both the Pre- and Post-Restructuring Periods

Average residential electricity prices				
	Pre-restructuring Period 1990-1995		Post- restructuring Period 1996-2004	
Restructured Jurisdictions	9.02		9.41	
Non-restructured Jurisdictions	7.23		7.75	
	Case I	Case II	Case I	Case II
n_1	144	144	216	216
n_2	162	162	243	243
df	304	265	457	454
s_1^2	4.29	4.29	4.60	4.60
s_2^2	2.42	2.42	4.75	4.75
s	0.21	0.21	0.20	0.20
M_2-M_1	1.79	1.79	1.66	1.66
t	8.58**	8.44**	8.18**	8.19**
t* (α=0.01)	2.59	2.59	2.59	2.59

** Significant at 1% level of significance

So far the analysis has examined and compared average electricity prices for the restructured jurisdictions, the non-restructured jurisdictions, and all 51 jurisdictions as whole for the pre- and post-restructuring periods. On a very general level, this analysis indicates that average residential electricity prices have increased at a higher rate in the non-restructured jurisdictions relative to the restructured jurisdictions, and that volatility has increased in both types of jurisdictions though relatively more in the non-restructured jurisdictions. These findings seem to contradict reported experiences of customers in several restructured jurisdictions,[23] which is why a closer look at the individual jurisdictions is warranted. Thus, the same analysis on rate of change in electricity prices, the significance of this change, and the change in volatility, will be conducted for individual jurisdictions to determine if changes have been masked by the process of averaging used in the previous analysis.

Since each jurisdiction is being considered separately in this analysis, rather than using 1996 as the year that distinguishes between the restructured and non-restructured periods, the year in which the restructuring legislation was passed in each restructured jurisdiction will be used to distinguish the two periods. Table 5.7 provides details of the analysis of electricity price changes between the pre -and post-restructuring periods for each of the 24 jurisdictions that restructured their electricity markets. This snapshot of average electricity prices indicates that in 8 jurisdictions (33% of the restructured jurisdictions),

[23] See, for example, Davidson (2007).

electricity prices actually declined after restructuring, with the greatest decline being 11.59% in Illinois.

As shown in Table 5.7, in nine jurisdictions (37% of the 24 restructured jurisdictions), average electricity prices increased by more than 5%, with the highest increase being 25.88% for Nevada. The remaining seven jurisdictions either showed minuscule price changes or a price increase of less than 5%. Table 5.7 also indicates that, with the exception of the price changes in New Hampshire and California, most of the larger price changes (5 jurisdictions with price declines and 7 with price increases) were statistically significant at a 5% level of significance. In contrast to the findings in Tables 5.5 and 5.6, the results in Table 5.7 are sensitive to the type of test used for three jurisdictions, that is, whether the assumption of equal variances is imposed (Case I) or not imposed (Case II). Specifically, for the District of Columbia and New Jersey, the Case I test indicates that the price change is insignificant while in the Case II test it is found to be significant. The opposite holds for Texas. Regardless, all in all, in the 24 jurisdictions that had implemented electricity market restructuring at the retail level, the average residential electricity price actually increased by 3.92% in the post restructuring period, which is lower than the 4.25% price increase (from 9.02 to 9.41 cents/kWh) determined in Table 5.5 when 1996 was used in all jurisdictions as the cutoff date for passing of legislation. In fact, allowing for these different years in which the legislation was passed, the average price over all 24 restructured jurisdictions increased by approximately 3.19% (from 9.09 cents / kWh to 9.38 cents / kWh).

As far as volatility is concerned, Table 5.7 indicates that the average variance of the electricity prices in the restructured jurisdictions actually decreased by 24% from the pre- to the post-restructuring period. This is in stark contrast to the general analysis in Table 5.5 which showed that volatility for these jurisdictions actually increased by 7.23% from the pre- to the post-restructuring period. This reversal in results, just like the difference in price increases, may be explained by the artificial distinction of the pre- and post-restructuring periods using the year 1996 for the general analysis in Table 5.5. Nevertheless, this decrease in volatility seems to be a surprising result for restructured jurisdictions.

Note that the finding of price decreases subsequent to restructuring for 8 restructured jurisdictions cannot be directly attributed to the restructuring that occurred, not only because of the role of other variables, but also because of the fact that in many jurisdictions some form of price cap and/or regulations were imposed at the onset of market restructuring. Of course, it should also be noted that many jurisdictions that did not restructure their electricity markets also imposed such price controls. Table 5.8 identifies a sample of both restructured and non-restructured jurisdictions that imposed rate reductions or freezes.

Table 5.7: Significance of Change in Average Residential Electricity Price between the Pre- and Post-Restructuring Periods for Individual Jurisdictions that Implemented Electricity Market Restructuring

Jurisdiction (1)	Legislation date (2)	pre legislation (3)	post legislation (4)	% change (5)	n_1 (6)	n_2 (7)	s_1^2 (8)	s_2^2 (9)
Arizona	1998	9.20	8.43	**-8.30%**	8	7	0.09	0.02
Connecticut	1998	11.32	11.30	**-0.24%**	8	7	0.58	0.17
Delaware	1999	8.89	8.73	**-1.77%**	9	6	0.08	0.05
District of Columbia	2000	7.32	7.93	8.31%	10	5	0.46	0.01
Illinois	1997	10.15	8.97	**-11.59%**	7	8	1.46	0.12
Maine	1997	11.42	12.72	11.32%	7	8	1.46	0.12
Maryland	1999	8.13	7.88	**-3.05%**	9	6	0.15	0.07
Massachusetts	1997	10.75	11.20	4.10%	7	8	0.34	0.62
Michigan	2000	8.32	8.35	0.31%	10	5	0.08	0.01
New Hampshire	1996	11.80	12.96	9.86%	6	9	1.74	0.59
New Jersey	1999	11.38	10.69	**-6.04%**	9	6	0.36	0.26
New York	1996	12.74	13.94	9.39%	6	9	0.91	0.16
Ohio	1999	8.43	8.44	0.02%	9	6	0.06	0.03
Oregon	1999	5.26	6.55	24.36%	9	6	0.16	0.43
Pennsylvania	1996	9.55	9.62	0.70%	6	9	0.03	0.10
Rhode Island	1996	11.02	11.37	3.23%	6	9	0.36	0.65
Texas	1999	7.73	8.55	10.68%	9	6	0.07	0.69
Virginia	1999	7.58	7.72	1.84%	9	6	0.04	0.04
Arkansas	2001	7.88	7.39	**-6.24%**	11	4	0.10	0.05
Montana	1997	5.87	6.96	18.61%	7	8	0.06	0.29
Nevada	1997	6.49	8.18	25.88%	7	8	0.35	1.52
New Mexico	1999	9.00	8.60	**-4.52%**	9	6	0.01	0.02
Oklahoma	1997	6.93	7.00	1.11%	7	8	0.05	0.20
California	1996	11.03	11.70	6.03%	6	9	0.35	0.85
			Avg. chg.	3.92%			0.39	0.29

…continued

Table 5.7 (continued)

Jurisdiction (1)	M_2-M_1 (10)	CASE I S (11)	CASE I df (12)	CASE I t (13)	CASE I t* (14)	CASE II S (15)	CASE II df (16)	CASE II t (17)	CASE II t* (18)
Arizona	(0.76)	0.13	13	**(5.82)**	2.16	0.13	11	**(6.08)**	2.19
Connecticut	(0.03)	0.35	13	(0.08)	2.16	0.33	12	(0.08)	2.17
Delaware	(0.16)	0.15	13	(1.08)	2.16	0.14	14	(1.11)	2.14
District of Columbia	0.61	0.33	13	1.86	2.16	0.23	10	**2.63**	2.22
Illinois	(1.18)	0.32	13	**(3.68)**	2.16	0.30	9	**(3.91)**	2.28
Maine	1.29	0.48	13	**2.69**	2.16	0.51	7	**2.53**	2.35
Maryland	(0.25)	0.20	13	(1.26)	2.16	0.18	15	(1.36)	2.13
Massachusetts	0.44	0.39	13	1.14	2.16	0.38	15	1.16	2.14
Michigan	0.03	0.14	13	0.18	2.16	0.11	14	0.24	2.15
New Hampshire	1.16	0.58	13	2.00	2.16	0.65	8	1.79	2.31
New Jersey	(0.69)	0.32	13	(2.15)	2.16	0.31	14	**(2.21)**	2.15
New York	1.20	0.38	13	**3.11**	2.16	0.45	7	**2.66**	2.40
Ohio	0.00	0.12	13	0.01	2.16	0.12	15	0.01	2.14
Oregon	1.28	0.29	13	**4.37**	2.16	0.33	8	**3.94**	2.29
Pennsylvania	0.07	0.15	13	0.44	2.16	0.14	15	0.49	2.14
Rhode Island	0.36	0.41	13	0.86	2.16	0.39	15	0.91	2.13
Texas	0.83	0.32	13	**2.59**	2.16	0.38	6	2.16	2.47
Virginia	0.14	0.11	13	1.28	2.16	0.11	13	1.28	2.17
Arkansas	(0.49)	0.18	13	**(2.68)**	2.16	0.16	9	**(3.01)**	2.26
Montana	1.09	0.24	13	**4.58**	2.16	0.23	11	**4.80**	2.20
Nevada	1.68	0.55	13	**3.06**	2.16	0.52	11	**3.20**	2.19
New Mexico	(0.41)	0.07	13	**(5.70)**	2.16	0.08	10	**(5.41)**	2.22
Oklahoma	0.08	0.20	13	0.39	2.16	0.19	12	0.40	2.18
California	0.67	0.46	13	1.46	2.16	0.42	15	1.59	2.13

Note: Critical values for t tests are for a 5% level of significance.

Table 5.8: Some Jurisdictions that Imposed Rate Reductions or Freezes[24]

Utility	Jurisdiction	Action Imposed
Restructured Jurisdictions		
Boston Edison	MA	Inflation adjusted rate reduction (1999)
Commonwealth Edison	IL	Rate freeze until Jan 1, 2001
Detroit Edison	MI	Rate reduction followed by a freeze until Jan 2004
Reliant Energy	TX	Rate freeze for customers with less than 1 MW consumption
Consolidated Edison	NY	Rate reduction (1998)
Pacific Gas and Electric	CA	Rate freeze until March, 2002
Non-restructured Jurisdictions		
Florida Power and Light	FL	Reduction applicable to energy component only (1999)
Hydro Quebec	QE	rate freeze until April, 2004
Nova Scotia power	NS	rate freeze until 2001
Sask power	SK	rate freeze until Jan 2000
BC Hydro	BC	rate freeze until March 31, 2003

Source: Comparison of Electricity Prices in Major North American Cities, Hydro Quebec Publications

A similar analysis to that provided in Table 5.7 can also be conducted for individual jurisdictions that did not pursue electricity market restructuring. Obviously, in the absence of restructuring legislation dates, it is necessary to choose a year to distinguish the two periods, and for this purpose the year 1996 is again chosen. Table 5.9 summarizes the findings on the rate of change in electricity prices, the significance of this change, and the change in volatility for these jurisdictions.

Table 5.9 indicates that of the 27 jurisdictions that did not restructure, 14 (52%) showed a statistically significant price increase of more than 5%, whereas only 4 (15%) showed a price decrease and these decreases were only statistically significant at a 5% level for two jurisdictions. The results here are sensitive to the type of test used for Colorado, Florida and North Dakota, where the price changes are deemed statistically significant only by the Case II (unequal variances) test. Nevertheless, in the parallel context of restructured jurisdictions, electricity prices declined in 8 jurisdictions (33%) post restructuring, and were only statistically significant in 5 cases. In nine jurisdictions (37%) average electricity prices

[24] Swadley and Yucel (2011) provide a list of 17 restructured jurisdictions, 15 of which are noted as having imposed rate caps. However, the details on non-restructured jurisdictions having rate caps are not provided and would require a detailed examination of each jurisdiction by searching through fragmented information at the Energy Information Administration EIS website of the US DOE.

increased by more than 5%, and were statistically significant at the 5% level in 7 cases.

Overall for these 27 jurisdictions that did not pursue restructuring, electricity prices rose by 6.51% and volatility rose by 119.48% from the pre- to the post-restructuring period. For jurisdictions that did restructure, average residential electricity price increased only by 3.92%, whereas the average variance of the electricity prices actually decreased by 24% from the pre- to the post-restructuring period.

Table 5.9: Significance of Change in Average Residential Electricity Price between the Pre- and Post-Restructuring Periods for Individual States that Did Not Implement Electricity Market Restructuring

Jurisdiction	pre 1996	post 1996	% change	s_1^2	s_2^2	M_2-M_1
Alaska	10.89	11.72	**7.69%**	0.21	0.19	0.84
Alabama	6.70	7.06	**5.38%**	0.01	0.09	0.36
Colorado	7.22	7.61	**5.36%**	0.02	0.15	0.39
Florida	7.84	8.19	4.57%	0.01	0.18	0.36
Georgia	7.68	7.68	0.09%	0.03	0.01	0.01
Hawaii	11.62	15.59	**34.18%**	1.52	1.98	3.97
Iowa	7.99	8.42	**5.35%**	0.03	0.05	0.43
Idaho	5.02	5.70	**13.66%**	0.03	0.29	0.69
Indiana	6.78	6.97	2.86%	0.01	0.02	0.19
Kansas	7.87	7.70	-2.19%	0.00	0.00	(0.17)
Kentucky	5.69	5.66	-0.59%	0.00	0.04	(0.03)
Louisiana	7.49	7.52	0.47%	0.03	0.14	0.04
Minnesota	7.03	7.48	**6.43%**	0.02	0.06	0.45
Missouri	7.33	7.04	-3.92%	0.01	0.00	(0.29)
Mississippi	6.99	7.25	3.66%	0.01	0.19	0.26
North Carolina	8.06	8.13	0.79%	0.02	0.03	0.06
North Dakota	6.29	6.45	2.59%	0.00	0.03	0.16
Nebraska	6.25	6.58	**5.26%**	0.01	0.05	0.33
South Carolina	7.32	7.69	**5.03%**	0.03	0.05	0.37
South Dakota	7.02	7.35	4.62%	0.01	0.04	0.32
Tennessee	5.77	6.34	**10.01%**	0.01	0.08	0.58
Utah	6.99	6.76	-3.20%	0.01	0.09	(0.22)
Vermont	9.78	12.19	**24.66%**	0.19	0.48	2.41
Washington	4.63	5.55	**19.90%**	0.08	0.39	0.92
Wisconsin	6.89	7.73	**12.20%**	0.03	0.61	0.84
West Virginia	6.19	6.27	1.29%	0.06	0.00	0.08
Wyoming	6.02	6.61	**9.68%**	0.00	0.16	0.58
		Avg. chg.	6.51%	0.09	0.19	

…continued

Table 5.9 (continued)

Jurisdiction	Case I				Case II			
	s	df	t	t*	s	df	t	t*
Alaska	0.25	13	**3.35**	2.16	0.25	12	**3.29**	2.18
Alabama	0.14	13	**2.67**	2.16	0.11	10	**3.22**	2.23
Colorado	0.18	13	2.14	2.16	0.16	12	**2.49**	2.17
Florida	0.19	13	1.88	2.16	0.16	10	**2.28**	2.24
Georgia	0.07	13	0.11	2.16	0.08	8	0.09	2.32
Hawaii	0.76	13	**5.24**	2.16	0.74	14	**5.35**	2.15
Iowa	0.12	13	**3.53**	2.16	0.12	15	**3.72**	2.14
Idaho	0.24	13	**2.82**	2.16	0.20	11	**3.35**	2.20
Indiana	0.07	13	**2.76**	2.16	0.06	14	**3.10**	2.14
Kansas	0.03	13	**(5.19)**	2.16	0.03	14	**(5.81)**	2.14
Kentucky	0.09	13	(0.39)	2.16	0.07	10	(0.47)	2.23
Louisiana	0.18	13	0.20	2.16	0.16	14	0.22	2.15
Minnesota	0.12	13	**3.87**	2.16	0.11	15	**4.25**	2.13
Missouri	0.04	13	**(7.78)**	2.16	0.04	10	**(7.24)**	2.24
Mississippi	0.20	13	1.30	2.16	0.16	9	1.59	2.25
North Carolina	0.09	13	0.73	2.16	0.08	14	0.76	2.14
North Dakota	0.08	13	2.12	2.16	0.07	12	**2.49**	2.18
Nebraska	0.10	13	**3.16**	2.16	0.09	13	**3.66**	2.16
South Carolina	0.12	13	**3.17**	2.16	0.11	15	**3.39**	2.13
South Dakota	0.09	13	**3.52**	2.16	0.08	12	**4.12**	2.18
Tennessee	0.13	13	**4.35**	2.16	0.11	12	**5.11**	2.18
Utah	0.14	13	(1.59)	2.16	0.12	12	(1.87)	2.18
Vermont	0.34	13	**7.03**	2.16	0.31	15	**7.68**	2.13
Washington	0.29	13	**3.17**	2.16	0.25	13	**3.64**	2.16
Wisconsin	0.35	13	**2.41**	2.16	0.29	10	**2.93**	2.24
West Virginia	0.09	13	0.89	2.16	0.11	5	0.72	2.53
Wyoming	0.18	13	**3.31**	2.16	0.14	9	**4.07**	2.28

Note: For all jurisdictions, $n_1 = 6$ and $n_2 = 9$. The critical value for t tests is for a 5% level of significance.

Analysis at the level of individual jurisdictions, while providing different numerical values, confirms the results from the previous more general analysis that indicated that electricity prices increased by a smaller percentage for restructured jurisdictions than for non-restructured jurisdictions. In addition, volatility in electricity prices in non-restructured jurisdictions increased much more in the post-restructuring period than did volatility in the restructured jurisdictions. Regardless, electricity prices were clearly increasing between the two periods in US jurisdictions irrespective of whether or not electricity market restructuring occurred.

On the basis of the above analysis, the following conclusions can be reached:

1) Jurisdictions that pursued electricity market restructuring had higher average residential electricity prices in the 1990-1995 period than those jurisdictions that did not pursue restructuring, and the difference between the two is statistically significant.

2) From the pre- to the post-restructuring period based on 1996 as the transition year, average residential electricity prices have increased at a higher rate in the non-restructured jurisdictions relative to the restructured jurisdictions. The difference between the average electricity prices in the two types of jurisdictions in the post-restructuring period is also statistically significant.

3) The difference between the pre- and post-restructuring electricity prices for non-restructured jurisdictions is significant; however, the change in the electricity prices for restructured jurisdictions between the two periods is statistically insignificant.

4) Volatility of electricity prices has increased in both types of jurisdictions, though relatively more in the non-restructured jurisdictions.[25]

5) The analysis which takes into account the different years of passing of restructuring legislation indicates that the average variance of the electricity prices of the restructured jurisdictions actually decreased by 24% from the pre- to the post-restructuring period.

In view of these conclusions, one cannot infer that restructuring has been responsible for either price increases or increased volatility without controlling for the effect of changes in other variables like generation capacity, fuel consumption mix and fuel prices. The behaviour of these variables in the pre- and post-restructuring periods for the various US jurisdictions is considered next.

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[25] On the basis of the information on rate caps instituted in restructured jurisdictions provided by Swadley and Yucel (2011), when the variance of electricity prices was computed separately for restructured jurisdictions with rate caps and for those without rate caps, it was found that the electricity price volatility of the restructured jurisdictions with price caps actually decreased by 23.91% in the post restructuring period, whereas the electricity price volatility of the restructured jurisdictions without price caps increased by 32.48% in the post restructuring period. However, as noted earlier, Davidson (2007) and Swadley and Yucel (2011) have very different definitions of which jurisdictions had retail electricity price caps, so these results can only be viewed as preliminary. In any event, electricity price volatility in the non-restructured jurisdictions increased by 119.48% post 1996, and, based on the above calculations, removing the non-restructured jurisdictions with rate caps, if any, might be expected to increase calculated electricity price volatility. Given that restructured jurisdictions without rate caps experienced an increase in electricity price volatility of only 32.48% in the post restructuring period, this indicates at a preliminary level at least that regardless of whether or not there were rate caps, electricity price volatility did increase in the non-restructured jurisdictions.

5.5.3 Explanatory Variables

The regression model used to explain electricity prices includes variables such as coal- and natural gas-based capacity, coal- and natural gas-based generation, coal- and natural gas-based utilization and heat rates on the one hand, and economic growth, heating degree days, coal and natural gas prices, annual wages per worker and the user cost of capital on the other. As described earlier, the former set of explanatory variables is treated as endogenous in the sense that these variables, like electricity prices, are affected by restructuring, whereas the latter set of variables is treated as exogenous.

Many US jurisdictions have significant hydro- and nuclear-based capacities, and for the purpose of our comparative analysis, these variables are also considered, along with data on fuel consumption, which forms the basis for determining heat rates. Fuel consumption data on coal (short tons) and natural gas (MCF) consumption were converted to units of GJ equivalents using standard conversions, and then summed together so that the percentage of coal consumption could be determined. The heat content data were not used in these calculations as the purpose is not to obtain the true energy equivalent, but only to determine percentage share of each fuel in total coal and natural gas consumption.

The capacity data in units of MW and generation data in units of MWh were also converted to percentage shares for convenience for the comparative analysis. Data on capacity, fuel consumption, generation, and hence heat rates and capacity utilization, are available from 1990 – 2004, whereas data on gas prices are available from 1967 – 2004, coal prices from 1985 – 2004, heating degree days from 1993 - 2005 and wage/worker from 1969 – 2005. For the purpose of making general comparisons between the restructured and non-restructured jurisdictions, as well as for determining the quantitative effect of restructuring on the explanatory endogenous variables, the data period that is considered here is from 1990 onwards.

5.5.3.1 Overview of Data Availability, Anomalies, and Drastic Changes

Before beginning a general analysis of the data on the explanatory variables for the US jurisdictions, some observations on the availability and oddities of the data will be presented. Details of these issues are presented in Appendix 5.1.

A commonly encountered problem with data for many of the jurisdictions concerns sudden large changes in the values for particular variables from one year to the next. As shown in Appendix 5.1, for some jurisdictions there is a drastic shift in the data for some jurisdictions after a certain year, others have 0% or 100% as values for the respective variables, and in still others there are various oddities such as a sudden value of zero for a particular year or negative values in some years for some of the variables. As a result values for several variables that are determined as the ratio of two of these variables cannot be determined in some years. These issues plague most of the variables, including fuel consumption, capacity, and generation, and hence heat rates and capacity utilization. In terms of HDD, fuel prices and wage per worker, data on these variables are unavailable in many jurisdictions for particular years.

To summarize the findings in Appendix 5.1, drastic changes observed in jurisdictions that restructured their electricity markets are also observed in some of the jurisdictions that did not restructure their electricity markets. Based on detailed analysis for a selection of jurisdictions, it is not possible to deduce a general pattern for restructured and non-restructured jurisdictions. In particular, changes such as a shift from coal to natural gas capacity, or vice versa, or drastic decreases in generation and capacity shares, are observed to occur in both restructured and non-restructured jurisdictions, and therefore cannot be readily identified as being the result of restructuring.

5.5.3.2 General Analysis

The analysis of the data on the explanatory variables for the 51 US jurisdictions was conducted in light of the analysis of electricity prices in Section 5.5.2, where it was found that for the 24 jurisdictions that are considered to have restructured their electricity markets, average electricity prices in 8 jurisdictions actually fell in the post-restructuring period as defined by the year of restructuring legislation enactment. Among the 27 jurisdictions that did not restructure their electricity market, average electricity prices fell post-1996 in only 4 jurisdictions.

As mentioned earlier, the year 1996 was the earliest date at which restructuring legislation was enacted in any of the restructured jurisdictions. Thus, while the partitioning of the data has no particular meaning in the context of non-restructured jurisdictions, it is chosen for comparison purposes. The restructured jurisdictions in which the average electricity price decreased in the post restructuring period are Arizona, Connecticut, Delaware, Illinois, Maryland, New Jersey, Arkansas and New Mexico, while the non-restructured counterparts are Kansas, Kentucky, Missouri and Utah.

Overall, it appears that generally, average electricity prices would have risen in the post-restructuring period with or without the presence of restructuring. Among the eight restructured jurisdictions where the price fell after restructuring, the average electricity price decline is 5.21%, whereas the decline is only 2.58% among the four states that did not restructure their electricity markets and where prices fell in the same period. Moreover, the electricity price increases in the 16 restructured jurisdictions with price increases averages 7.70%, whereas among the corresponding 23 jurisdictions that did not restructure the average electricity price increase is 8.72%. Thus, the evidence suggests that average electricity prices generally (but not uniformly) increased in both types of jurisdictions, and that they tended to increase more in jurisdictions that did not restructure their electricity markets.

As indicated in Table 5.10, however, this analysis is sensitive to the jurisdictions used in computing the average price increase or decline. If the three jurisdictions exhibiting the greatest percentage price increases for both types of jurisdictions – Oregon, Montana and Nevada from restructured jurisdictions and Hawaii, Vermont and Washington from non-restructured jurisdictions – are omitted from the analysis, the price increase becomes 5.52%, for restructured jurisdictions and 5.17% for the non-restructured jurisdictions. This seems to indicate that excluding particular jurisdictions where specific (unidentified) factors may have played an important role, average electricity prices would have increased by a similar percentage in both restructured and non-restructured jurisdictions, although possibly by a slightly greater percentage on average in jurisdictions that restructured their electricity markets.

Table 5.10: Average Electricity Prices for Particular Sub-categories of the Restructured and Non-Restructured Jurisdictions

Average electricity prices	Pre 1996 (legislation)	Post 1996 (legislation)	% change
All Restructured jurisdictions (24)	9.09	9.38	3.20%
All Non-restructured jurisdictions (27)	7.23	7.74	7.11%
Restructured jurisdictions with price increases (16)	8.89	9.57	7.70%
Restructured jurisdictions with price decreases (8)	9.49	9.00	-5.21%
Non-Restructured jurisdictions with price increases (23)	7.28	7.92	8.72%
Non-Restructured jurisdictions with price decreases (4)	6.97	6.79	-2.58%
Restructured jurisdictions with price increases, excluding 3 with largest price changes (13)	9.59	10.12	5.52%
Non-Restructured jurisdictions with price increases, excluding 3 with largest price changes (20)	7.07	7.44	5.17%

While the average price increase in the two types of jurisdictions is sensitive to the sets of jurisdictions included in the analysis, it is clear that average prices declined at a greater percentage in restructured jurisdictions, and in fact given the larger number of jurisdictions where the average electricity prices fell it seems that restructuring may have contributed towards reducing the average electricity price. However, the role of other variables like capacity, demand and fuel prices also needs to be addressed to obtain a clearer picture for each of the four categories of jurisdictions – restructured jurisdictions where average prices fell after restructuring legislation, restructured jurisdictions where average prices rose after restructuring legislation, non-restructured jurisdictions where prices fell after 1996 and non-restructured jurisdictions where average prices rose after 1996. In addition, the values of variables in the restructured jurisdictions as a whole, and in the non-restructured jurisdictions as a whole, are also considered.

Table 5.11 contains data on 24 explanatory variables relevant to the electricity price estimation equation. Capacity and generation data are subdivided into coal-, natural gas-, nuclear- and hydro-based variables, as well as totals, while consumption data are provided for coal, natural gas, and in total. Fuel prices are subdivided into coal and natural gas prices. Likewise, heat rates and capacity utilization are provided for coal- and natural gas-based data. Real GDP is presented both in level and growth forms, as is wage per worker. Finally, information on heating degree days is also included. The average values of these variables are computed for separately for 1990 – 1995 and for 1996 – 2004 for jurisdictions that did not restructure their electricity markets, and for the pre restructuring and post restructuring periods for US jurisdictions that restructured their electricity markets. The pre-restructuring period begins in 1990 and ends one year prior to the year of legislation enactment. The post-restructuring period starts from the year legislation was enacted and ends in 2004 for most variables excluding wages, real GDP and HDD, where the ending year is 2005. For comparison purposes, and for later use, data for Alberta are also provided in Table 5.11. Alberta data on natural gas and coal prices, real GDP and wages were converted to units of US equivalents by using the Canada-US exchange rate. Details of this conversion are presented in Section 5.6.2, where the values of particular variables for Alberta and US jurisdictions are compared.

The change between the two periods for both types of jurisdictions is computed both as a percentage change and as a difference (which in some cases is expressed in percentage points). Although the percentage change has an advantage over taking differences as it is independent of units, care has to be taken in interpretation. For instance, a 100% change from 1 to 2 units might appear large, but may be trivial compared to say a 50% change from 20 to 30 units. Hence changes are reported in both percentage terms and as differences. The importance of this point becomes clearer when changes in variables are considered across jurisdictions, where some jurisdictions show changes in the 200% range for a variable, although this may be a relatively small amount expressed in terms of units. If these percentage changes were to be applied to modify the values of Alberta data on the same variable in the post-restructuring period, and Alberta had much higher initial levels of that variable, applying a 200% change to that variable would be unlikely to be appropriate. Finally, in addition to percentage and level changes, Table 5.11 also indicates the number of jurisdictions where the value of the variables increased or decreased.

Table 5.11: Average Values of and Changes in Explanatory Variables for the Four Types of US jurisdictions

Explanatory Variable	NON-RESTRUCTURED JURISDICTIONS			Alberta
	4 jurisdictions with price decreases *Category A*	**23 jurisdictions with price increases *Category B***	**All 27 Jurisdictions (4)**	
Coal capacity				
Share pre 1996	75.91%	46.77%	**61.34%**	68.39%
Share post 1996	71.05%	43.64%	**57.34%**	57.51%
% change	-6.40%	-6.70%	**-6.52%**	-15.90%
difference (% points)	-4.86	-3.13	**-4.00**	-10.87
# with increases	0	2	**2**	
# with decreases	4	18	**22**	
Hydro capacity				
Share pre 1996	3.04%	16.33%	**9.68%**	10.34%
Share post 1996	3.03%	15.75%	**9.39%**	8.81%
% change	-0.35%	-3.55%	**-3.04%**	-14.84%
difference (% points)	-0.01	-0.58	**-0.29**	-1.54
# with increases	1	4	**5**	
# with decreases	2	16	**18**	
Natural gas capacity				
Share pre 1996	3.15%	3.24%	**3.20%**	20.98%
Share post 1996	5.60%	5.42%	**5.51%**	33.03%
% change	77.66%	67.10%	**72.30%**	57.42%
difference (% points)	2.45	2.18	**2.31**	12.05
# with increases	4	19	**23**	
# with decreases	0	2	**2**	
Nuclear capacity				
Share pre 1996	4.75%	12.11%	**8.43%**	0.00%
Share post 1996	4.51%	10.81%	**7.66%**	0.00%
% change	-4.91%	-10.79%	**-9.14%**	
difference (% points)	-0.23	-1.31	**-0.77**	0.00
# with increases	0	2	**2**	
# with decreases	2	12	**14**	

…continued

Table 5.11 (continued)

Explanatory Variable	**RESTRUCTURED JURISDICTIONS** 8 jurisdictions with price decreases *Category C*	16 jurisdictions with price increases *Category D*	All 24 Jurisdictions	**Alberta**
Coal capacity				
Share pre 1996	37.70%	37.51%	**37.61%**	68.39%
Share post 1996	31.81%	33.83%	**32.82%**	57.51%
% change	-15.63%	-9.82%	**-12.74%**	-15.90%
difference (% points)	-5.89	-3.69	**-4.79**	-10.87
# with increases	2	3	**5**	
# with decreases	6	9	**15**	
Hydro capacity				
Share pre 1996	4.34%	14.94%	**9.64%**	10.34%
Share post 1996	5.84%	20.29%	**13.07%**	8.81%
% change	34.69%	35.81%	**35.56%**	-14.84%
difference (% points)	1.50	5.35	**3.43%**	-1.54
# with increases	6	9	**15**	
# with decreases	0	6	**6**	
Natural gas capacity				
Share pre 1996	8.52%	8.01%	**8.26%**	20.98%
Share post 1996	5.07%	8.48%	**6.78%**	33.03%
% change	-40.45%	5.89%	**-17.99%**	57.42%
difference (% points)	-3.45	0.47	**-1.49**	12.05
# with increases	4	8	**12**	
# with decreases	4	5	**9**	
nuclear capacity				
Share pre 1996	21.50%	12.84%	**17.17%**	0.00%
Share post 1996	12.80%	9.52%	**11.16%**	0.00%
% change	-40.45%	-25.85%	**-34.99%**	
difference (% points)	-8.70	-3.32	**-6.01**	0.00
# with increases	0	3	**3**	
# with decreases	6	8	**14**	

…continued

Table 5.11 (continued)

Explanatory Variable	NON-RESTRUCTURED JURISDICTIONS			Alberta
	4 jurisdictions with price decreases *Category A*	23 jurisdictions with price increases *Category B*	All 27 Jurisdictions	
total capacity				
pre 1996	12,524	12,538	**12,531**	7,990
post 1996	13,017	13,335	**13,176**	9,950
% change	3.93%	6.35%	**5.14%**	24.54%
difference	493	797	**645**	1,960
# with increases	3	19	**22**	
# with decreases	1	4	**5**	
coal based generation				
Share pre 1996	85.55%	53.61%	**69.58%**	83.64%
Share post 1996	86.78%	52.61%	**69.70%**	71.16%
% change	1.45%	-1.86%	**0.17%**	-14.93%
difference (% points)	1.24	-1.00	**0.12%**	-12.48
# with increases	2	9	**11**	
# with decreases	2	11	**13**	
hydro based generation				
Share pre 1996	2.48%	15.47%	**8.97%**	4.07%
Share post 1996	2.05%	15.21%	**8.63%**	3.21%
% change	-17.23%	-1.64%	**-3.79%**	-21.22%
difference (% points)	-0.43	-0.25	**-0.34**	-0.86
# with increases	1	5	**6**	
# with decreases	3	16	**19**	
nat. gas based generation				
Share pre 1996	2.09%	6.51%	**4.30%**	12.15%
Share post 1996	2.42%	7.45%	**4.93%**	24.62%
% change	15.74%	14.43%	**14.75%**	102.64%
difference (% points)	0.33	0.94	**0.63**	12.47
# with increases	3	16	**19**	
# with decreases	1	5	**6**	

…continued

Table 5.11 (continued)

Explanatory Variable	RESTRUCTURED JURISDICTIONS			Alberta
	8 jurisdictions with price decreases *Category C*	16 jurisdictions with price increases *Category D*	All 24 Jurisdictions	
total capacity				
pre 1996	13,046	18,782	**15,914**	7,990
post 1996	7,001	13,892	**10,446**	9,950
% change	-46.34%	-26.04%	**-34.36%**	24.54%
difference	-6,046	-4,890	**-5,468**	1,960
# with increases	3	5	**8**	
# with decreases	5	11	**16**	
coal based generation				
Share pre 1996	48.10%	49.98%	**49.04%**	83.64%
Share post 1996	48.75%	47.46%	**48.10%**	71.16%
% change	1.35%	-5.04%	**-1.90%**	-14.93%
difference (% points)	0.65	-2.52	**-0.93**	-12.48
# with increases	4	6	**10**	
# with decreases	4	6	**10**	
hydro based generation				
Share pre 1996	3.36%	14.69%	**9.03%**	4.07%
Share post 1996	7.02%	20.38%	**13.70%**	3.21%
% change	109.02%	38.72%	**51.80%**	-21.22%
difference (% points)	3.66	5.69	**4.68**	-0.86
# with increases	2	8	**10**	
# with decreases	4	6	**10**	
nat. gas based generation				
Share pre 1996	7.53%	16.44%	**11.99%**	12.15%
Share post 1996	7.54%	13.84%	**10.69%**	24.62%
% change	0.09%	-15.83%	**-10.83%**	102.64%
difference (% points)	0.01	-2.60	**-1.30**	12.47
# with increases	4	7	**11**	
# with decreases	4	7	**11**	

…continued

Table 5.11 (continued)

Explanatory Variable	NON-RESTRUCTURED JURISDICTIONS			Alberta
	4 jurisdictions with price decreases *Category A*	**23 jurisdictions with price increases *Category B***	**All 27 Jurisdictions**	
nuclear based generation				
Share pre 1996	9.50%	18.21%	**13.86%**	0.00%
Share post 1996	8.25%	17.88%	**13.06%**	0.00%
% change	-13.19%	-1.83%	**-5.72%**	
difference (% points)	-1.25	-0.33	**-0.79**	0.00%
# with increases	0	6	**6**	
# with decreases	2	8	**10**	
total generation				
pre 1996	51,793,793	51,379,491	**51,586,642**	46,846,983
post 1996	60,004,838	59,878,967	**59,941,902**	58,939,122
% change	15.85%	16.54%	**16.20%**	25.81%
difference	8,211,044	8,499,476	**8,355,260**	12,092,139
# with increases	4	20	**24**	
# with decreases	0	3	**3**	
coal consumption				
Share pre 1996	97.33%	84.57%	**90.95%**	93.42%
Share post 1996	97.13%	76.93%	**87.03%**	87.55%
% change	-0.20%	-9.04%	**-4.31%**	-6.29%
difference (% points)	-0.20	-7.64	**-3.92**	-5.88
# with increases	1	3	**4**	
# with decreases	3	16	**19**	
natural gas consumption				
Share pre 1996	2.67%	15.43%	**9.05%**	6.58%
Share post 1996	2.87%	23.07%	**12.97%**	12.45%
% change	7.41%	49.55%	**43.33%**	89.30%
difference (% points)	0.20	7.64	**3.92**	5.88
# with increases	3	16	**19**	
# with decreases	1	4	**5**	

…continued

Table 5.11 (continued)

Explanatory Variable	RESTRUCTURED JURISDICTIONS			Alberta
	8 jurisdictions with price decreases *Category C*	**16 jurisdictions with price increases *Category D***	**All 24 Jurisdictions**	
nuclear based generation				
Share pre 1996	33.15%	19.18%	**26.17%**	0.00%
Share post 1996	21.66%	16.65%	**19.15%**	0.00%
% change	-34.68%	-13.23%	**-26.82%**	
difference (% points)	-11.50	-2.54	**-7.02**	0.00%
# with increases	0	3	**3**	
# with decreases	6	8	**14**	
total generation				
pre 1996	47,330,815	70,266,714	**58,798,764**	46,846,983
post 1996	33,627,451	57,547,433	**45,587,442**	58,939,122
% change	-28.95%	-18.10%	**-22.47%**	25.81%
difference	-13,703,363	-12,719,281	**-13,211,322**	12,092,139
# with increases	3	6	**9**	
# with decreases	5	10	**15**	
coal consumption				
Share pre 1996	83.23%	70.17%	**76.70%**	93.42%
Share post 1996	72.97%	73.92%	**73.44%**	87.55%
% change	-12.32%	5.34%	**-4.24%**	-6.29%
difference (% points)	-10.26	3.75	**-3.25**	-5.88
# with increases	3	6	**9**	
# with decreases	5	6	**11**	
natural gas consumption				
Share pre 1996	16.77%	29.83%	**23.30%**	6.58%
Share post 1996	27.03%	26.08%	**26.56%**	12.45%
% change	61.15%	-12.56%	**13.97%**	89.30%
difference (% points)	10.26	-3.75	**3.25**	5.88
# with increases	5	6	**11**	
# with decreases	3	6	**9**	

…continued

Table 5.11 (continued)

Explanatory Variable	NON-RESTRUCTURED JURISDICTIONS			Alberta
	4 jurisdictions with price decreases *Category A*	**23 jurisdictions with price increases *Category B***	**All 27 Jurisdictions**	
coal + gas consumption				
pre 1996	490,977,518	401,416,478	**446,196,998**	618,248,391
post 1996	612,203,834	468,916,401	**540,560,117**	703,886,655
% change	24.69%	16.82%	**21.15%**	13.85%
difference	121,226,316	67,499,922	**94,363,119**	85,638,264
# with increases	4	17	**21**	
# with decreases	0	4	**4**	
coal based utilization				
Share pre 1996	56.96%	57.97%	**57.46%**	81.71%
Share post 1996	68.42%	67.37%	**67.90%**	84.55%
% change	20.13%	16.22%	**18.16%**	3.48%
difference (% points)	11.46	9.40	**10.43**	2.84
# with increases	4	19	**23**	
# with decreases	0	1	**1**	
nat. gas based utilization				
Share pre 1996	8.67%	7.68%	**8.18%**	37.53%
Share post 1996	8.79%	12.22%	**10.51%**	51.51%
% change	1.43%	59.11%	**28.53%**	37.25%
difference (% points)	0.12	4.54	**2.33**	13.98
# with increases	2	15	**17**	
# with decreases	2	4	**6**	
coal based heat rate				
pre 1996	11,095	12,362	**11,728**	11,232
post 1996	11,355	12,100	**11,727**	11,201
% change	2.34%	-2.12%	**-0.01%**	-0.28%
difference	260	-262	**-1**	-31
# with increases	2	11	**13**	
# with decreases	2	9	**11**	

…continued

Table 5.11 (continued)

Explanatory Variable	**RESTRUCTURED JURISDICTIONS** 8 jurisdictions with price decreases ***Category C***	16 jurisdictions with price increases ***Category D***	**All 24 Jurisdictions**	**Alberta**
coal + gas consumption				
pre 1996	270,518,256	575,494,538	**423,006,397**	618,248,391
post 1996	232,591,540	445,650,904	**339,121,222**	703,886,655
% change	-14.02%	-22.56%	**-19.83%**	13.85%
difference	-37,926,716	-129,843,634	**-83,885,175**	85,638,264
# with increases	3	8	**11**	
# with decreases	5	6	**11**	
coal based utilization				
Share pre 1996	56.29%	61.82%	**59.05%**	81.71%
Share post 1996	59.58%	68.04%	**63.81%**	84.55%
% change	5.85%	10.07%	**8.06%**	3.48%
difference (% points)	3.29	6.23	**4.76**	2.84
# with increases	6	10	**16**	
# with decreases	2	2	**4**	
nat. gas based utilization				
Share pre 1996	11.92%	13.67%	**12.80%**	37.53%
Share post 1996	13.55%	21.71%	**17.63%**	51.51%
% change	13.66%	58.73%	**37.74%**	37.25%
difference (% points)	1.63	8.03	**4.83**	13.98
# with increases	5	5	**10**	
# with decreases	3	8	**11**	
coal based heat rate				
pre 1996	10,392	10,746	**10,569**	11,232
post 1996	10,441	10,983	**10,712**	11,201
% change	0.48%	2.21%	**1.36%**	-0.28%
difference	50	237	**143**	-31
# with increases	4	7	**11**	
# with decreases	4	5	**9**	

…continued

Table 5.11 (continued)

Explanatory Variable	**NON-RESTRUCTURED JURISDICTIONS**			**Alberta**
	4 jurisdictions with price decreases *Category A*	**23 jurisdictions with price increases *Category B***	**All 27 Jurisdictions**	
nat. gas based heat rate				
pre 1996	13,277	13,730	**13,504**	8,353
post 1996	12,900	12,408	**12,654**	6,064
% change	-2.84%	-9.63%	**-6.29%**	-27.41%
difference	-378	-1,322	**-850**	-2,289
# with increases	1	6	**7**	
# with decreases	3	13	**16**	
natural gas price				
pre 1996	2.18	2.62	**2.40**	1.33
post 1996	3.23	4.07	**3.65**	2.42
% change	48.17%	55.48%	**52.16%**	82.61%
difference	1.05	1.45	**1.25**	1.10
# with increases	4	20	**24**	
# with decreases	0	1	**1**	
coal price				
pre 1996	1.12	1.27	**1.19**	0.31
post 1996	0.96	1.16	**1.06**	0.30
% change	-13.57%	-8.62%	**-10.93%**	-2.37%
difference	-0.15	-0.11	**-0.13**	-0.01
# with increases	0	3	**3**	
# with decreases	4	16	**20**	
rgdp (millions)				
pre 1996	83,140	93,954	**88,547**	66,201
post 1996	110,325	127,932	**119,128**	78,646
% change	32.70%	36.16%	**34.54%**	18.80%
difference	27,185	33,977	**30,581**	12,445
# with increases	4	22	**26**	
# with decreases	0	1	**1**	

…continued

Table 5.11 (continued)

Explanatory Variable	**RESTRUCTURED JURISDICTIONS** 8 jurisdictions with price decreases *Category C*	16 jurisdictions with price increases *Category D*	All 24 Jurisdictions	**Alberta**
nat. gas based heat rate				
Pre legislation	12,201	13,052	**12,626**	8,353
Post legislation	12,113	11,690	**11,901**	6,064
% change	-0.72%	-10.44%	**-5.74%**	-27.41%
difference	-88	-1,362	**-725**	-2,289
# with increases	5	4	**9**	
# with decreases	3	9	**12**	
natural gas price				
pre legislation	2.31	2.23	**2.27**	1.33
post legislation	3.78	4.10	**3.94**	2.42
% change	63.33%	83.35%	**73.17%**	82.61%
difference	1.46	1.86	**1.66**	1.10
# with increases	8	14	**22**	
# with decreases	0	0	**0**	
coal price				
pre legislation	1.69	1.40	**1.55**	0.31
post legislation	1.56	1.36	**1.46**	0.30
% change	-7.55%	-3.05%	**-5.51%**	-2.37%
difference	-0.13	-0.04	**-0.09**	-0.01
# with increases	3	4	**7**	
# with decreases	5	8	**13**	
rgdp (millions)				
Pre legislation	144,369	235,803	**190,086**	66,201
Post legislation	186,694	302,355	**244,525**	78,646
% change	29.32%	28.22%	**28.64%**	18.80%
difference	42,325	66,553	**54,439**	12,445
# with increases	8	16	**24**	
# with decreases	0	0	**0**	

…continued

Table 5.11 (continued)

Explanatory Variable	NON-RESTRUCTURED JURISDICTIONS			Alberta
	4 jurisdictions with price decreases *Category A*	23 jurisdictions with price increases *Category B*	All 27 Jurisdictions	
rgdp growth				
pre 1996	3.47%	3.05%	**3.26%**	0.43%
post 1996	3.21%	3.13%	**3.17%**	4.64%
% change	-7.43%	2.54%	**-2.76%**	972.89%
difference (% points)	-0.26	0.08	**-0.09**	4.21
# with increases	1	12	**13**	
# with decreases	3	11	**14**	
hdd				
pre 1996	5,282	5,534	**5,408**	5,348
post 1996	5,026	5,259	**5,143**	5,349
% change	-4.84%	-4.96%	**-4.90%**	0.00%
difference	-256	-275	**-265**	0.18
# with increases	0	1	**1**	
# with decreases	4	20	**24**	
wage ($000/ workers)				
pre 1996	23,997	24,726	**24,361**	45,497
post 1996	56,850	56,229	**56,539**	62,803
% change	136.91%	127.41%	**132.09%**	38.04%
difference	32,853	31,503	**32,178**	17,305
# with increases	0	23	**23**	
# with decreases	4	0	**4**	
wage growth				
Pre legislation	4.25%	4.07%	**4.16%**	2.05%
Post legislation	4.46%	4.43%	**4.45%**	5.08%
% change	5.01%	8.84%	**6.88%**	147.34%
difference (% points)	0.21	0.36	**0.29**	3.02
# with increases	2	14	**16**	
# with decreases	2	9	**11**	

…continued

Table 5.11 (continued)

Explanatory Variable	**RESTRUCTURED JURISDICTIONS** **8 jurisdictions with price decreases** ***Category C***	**16 jurisdictions with price increases** ***Category D***	**All 24 Jurisdictions**	**Alberta**
rgdp growth				
pre 1996	3.85%	2.80%	**3.32%**	0.43%
post 1996	3.23%	3.16%	**3.20%**	4.64%
% change	-16.04%	12.81%	**-3.89%**	972.89%
difference (% points)	-0.62	0.36	**-0.13**	4.21
# with increases	1	11	**12**	
# with decreases	7	5	**12**	
hdd				
pre 1996	4,617	5,375	**4,996**	5,348
post 1996	4,461	5,198	**4,829**	5,349
% change	-3.38%	-3.29%	**-3.33%**	0.00%
difference	-156	-177	**-167**	0.18
# with increases	2	2	**4**	
# with decreases	6	13	**19**	
wage ($000/ workers)				
pre 1996	32,797	31,676	**32,236**	45,497
post 1996	68,521	61,436	**64,979**	62,803
% change	108.93%	93.95%	**101.57%**	38.04%
difference	35,725	29,761	**32,743**	17,305
# with increases	8	16	**24**	
# with decreases	0	0	**0**	
wage growth				
Pre legislation	4.22%	4.25%	**4.23%**	2.05%
Post legislation	4.82%	4.70%	**4.76%**	5.08%
% change	14.14%	10.70%	**12.42%**	147.34%
difference (% points)	0.60	0.45	**0.53**	3.02
# with increases	5	9	**14**	
# with decreases	3	6	**9**	

5.5.3.3 US Jurisdictions that Did Not Restructure their Electricity Markets.

According to Table 5.10, among the four US jurisdictions that did not restructure their electricity markets and where average electricity prices fell post 1996 – Kansas, Kentucky, Missouri and Utah (referred to below as Category A jurisdictions), the pre-1996 average electricity price is 6.97 cents/kWh. This price is lower than the pre-1996 average electricity price of 7.28 cents/kWh for the 23 jurisdictions that did not restructure their electricity markets but where electricity prices rose in the post 1996 period (referred to below as Category B jurisdictions). Some of the reasons for the lower electricity prices in the Category A jurisdictions may be ascertained from the information provided on the determinants of the electricity price in Table 5.11.[26]

According to Table 5.11, in the pre-1996 period average total capacity and average total generation were similar for both types of non-restructured jurisdictions, but the composition of their capacity and generation differed. Category A jurisdictions have a heavy dependence on coal, with an average coal capacity share of 75.91% compared to 46.77% for Category B jurisdictions. Similarly, the average share of coal based generation in Category A is 85.55% whereas in category B it is only 53.61%. Category A jurisdictions also have a lower dependence on both hydro- and nuclear-based capacity and generation.

Category A jurisdictions also exhibited lower average coal- and natural gas-based heat rates, which indicates that these jurisdictions were more efficient in operating their coal- and natural gas-based plants.[27] Coal and natural gas prices were also lower on average in these 4 jurisdictions in the pre-1996 period. While average real GDP growth in the pre-1996 period was greater in Category A, average heating degree days were lower. This suggests that the likely higher growth in demand for electricity in the Category A jurisdictions, as reflected in the higher average real GDP growth, is tempered by the lower demand due to the lower average heating degree days. Finally, average wages are also lower in Category A jurisdictions, although the average wage growth was higher than for the 23 Category B jurisdictions.

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[26] Note that in the absence of state-level CPI data that could be used to convert these prices to real terms, and since GDP deflators are not comparable over time due to a change in industrial classification (discussed earlier), nominal electricity prices are used in the comparisons and analysis here. While some differences in nominal electricity prices between different jurisdictions may be due to differences in inflation rates, the focus here is mainly on comparing jurisdictions where (nominal) prices decreased versus jurisdictions where they increased, rather than on differences in the extent to which electricity prices increased in different jurisdictions.

[27] Since data on the heat content of natural gas and of coal are available for the US as a whole but not for different US jurisdictions, it is not possible to ascertain to what extent average heat rates in Category A jurisdictions have been impacted by greater efficiency compared to, for example, access to a different quality of coal or natural gas. Since the same US-based heat content information has been used to compute heat rates for all jurisdictions, lower heat rates in Category A jurisdictions are presumably reflecting the impact of higher power plant efficiency.

These comparisons suggest that the reasons why electricity prices were lower in the pre-1996 period in the 4 Category A jurisdictions – Kansas, Kentucky, Missouri and Utah – may have included a higher dependence on coal-based capacity and generation, greater efficiency of coal and natural gas plants, and lower fuel prices. Definitive observations on the likely role of electricity demand are difficult to make due to conflicting information from real GDP growth and HDD. Similarly, a general conclusion on the likely role of wages is difficult to make given lower wages but higher wage growth for the Category A jurisdictions.

Information in Table 5.11 also indicates differences that may explain why electricity prices in the post-1996 period decreased for Category A jurisdictions but not for those in Category B. From the pre-1996 period to the post-1996 period, there has been a similar percentage decline in the average coal capacity share for both categories of non-restructured jurisdictions. However, the average share of coal capacity remains much higher for Category A jurisdictions. The average natural gas capacity share increased for both categories of non-restructured jurisdictions, although at a greater rate for those in Category A. Average total capacity and generation rose in both types of jurisdictions but at a greater rate in Category B jurisdictions. Coal- and natural gas-based utilization shares increased in both types of jurisdictions, although average natural gas-based utilization shares rose at a much higher rate in Category B, as did average gas prices. However, the natural gas-based heat rate decreases by more in Category B jurisdictions. Coal prices fell in both types of jurisdictions, but at a greater rate for those in Category A. Average real GDP growth increased slightly in Category B jurisdictions, but fell for those in Category A, although average growth rates remained higher in Category A in the post-1996 period. Average wage growth also increased at a higher rate in the Category B jurisdictions.

In summary, it appears that electricity prices may have fallen in the Category A jurisdictions due to a greater dependence on coal-based capacity and generation, lower use of natural gas-based plants as indicated by the much lower increase in the natural gas capacity utilization share figures, lower fuel prices in the post-1996 period, and a decline in average real GDP growth along with lower levels of heating degree days.

What is clear from this initial analysis of the non-restructured jurisdictions is that electricity prices fell for some jurisdictions (Category A) and increased for others (Category B) due to factors that are apparently unrelated to restructuring. With this background, we now examine the jurisdictions that did restructure their electricity markets.

5.5.3.4 US Jurisdictions that Restructured their Electricity Markets.

According to Table 5.10, among the restructured jurisdictions, average electricity prices fell in 8 of them (referred to subsequently as Category C jurisdictions) from an average of 9.49 cents/kWh in the pre-restructuring period to 9 cents/kWh in the post-restructuring period – a percentage decline of 5.21%.[28] In the remaining 16 jurisdictions (Category D), the average electricity price rose from an average 8.89 cents/kWh in the pre-restructuring period to 9.57 cents/kWh in the post-restructuring period – a percentage increase of 7.70%.

Reasons for higher average electricity prices for the Category C jurisdictions in the pre-restructuring period are suggested by the information in Table 5.11. Average total capacity and total generation are much lower in the Category C jurisdictions than in Category D jurisdictions. It may be recalled that such was not the case for the non-restructured jurisdictions, which both had similar average total capacity and generation in this period. While the composition percentages of coal- and natural gas-based capacities in the pre-restructuring period are similar for both types of jurisdictions, those in Category C were more dependent on nuclear capacity and less dependent on hydro capacity than were the Category D jurisdictions.

While pre-restructuring values of average natural gas capacity shares are similar in both types of jurisdictions, the average natural gas-based generation share is higher in Category D jurisdictions. Coal- and natural gas-based heat rates are lower in Category C jurisdictions, indicating a greater efficiency of their coal and gas plants, although fuel prices are higher in these jurisdictions. Compared to Category D jurisdictions, average real GDP growth for the Category C jurisdictions is higher, although heating degree days are lower.

In summary, higher average electricity prices in the Category C jurisdictions in the pre-restructuring period appear to be associated with factors such as higher fuel prices and higher average real GDP growth. The values of many other variables are either similar in range or would be expected to result in lower electricity prices, such as lower heat rates and heating degree days for Category C jurisdictions that indicate greater efficiency and lower demand. However, the smaller shares of hydro-based capacity and generation, and larger share of nuclear-based generation in a regulated environment may also have contributed to higher average electricity prices for Category C jurisdictions.

Information contained in Table 5.11 can also be used to study the relationship between changes in the explanatory variables and changes in average electricity prices in the post-restructuring period – declines for Category C jurisdictions and increases for Category D jurisdictions. Average total capacity

[28] Based on the information on rate caps provided by Swadley and Yucel (2011), of the 8 restructured jurisdictions where electricity prices fell in the post restructuring period, 5 of them – CT, DE, IL, MD and NJ – had instituted rate caps. The other three jurisdictions – AZ, AR and NM – for which Swadley and Yucel (2011) do not provide any information, are treated as not having instituted price caps. This simplification is made in view of the disagreement between Davidson (2007) and Swadley and Yucel (2011) in terms of the classification of jurisdictions on the basis of instituting retail electricity price caps. The resolution of this is left as a topic for future work.

and generation declined in both types of jurisdictions, but more so for those in Category C. Notable changes in the composition of capacity are in the greater declines of average coal, natural gas and nuclear capacity shares for Category C jurisdictions, also accompanied by larger decreases in the share of nuclear generation. In terms of the composition of generation, however, average shares of coal- and natural gas-based generation declined in Category D jurisdictions, but changed by a relatively small amount for jurisdictions in Category C. Interestingly, the share of hydro-based generation more than doubled for Category C jurisdictions.

A greater change in the average natural gas-based utilization share for Category D jurisdictions indicates a greater tightness in natural gas-based generation given that the share of natural gas-based generation declined in those jurisdictions, although average natural gas-based heat rates are lower in these same jurisdictions, indicating greater efficiency of the natural gas plants. It is to be noted that while greater tightness would tend to raise average electricity prices, the impact on electricity prices of greater efficiency would tend to be in the opposite direction.

As far as fuel prices are concerned, average natural gas prices increased more in Category D jurisdictions, and while average coal prices were lower in these same jurisdictions, the decrease in coal prices from the pre- to the post-restructuring period was greater in the Category C jurisdictions. Average real GDP also fell for jurisdictions in category C but rose in Category D. This indicates lower demand growth in the Category C jurisdictions, which is also supported by lower values of average HDD in the post- restructuring period. However, the effect of a higher average wage/worker for Category C jurisdictions in the post-restructuring period would be expected to act in the opposite direction.

In summary, the fall in average electricity prices appears to be associated with lower shares of natural gas-based utilization, lower natural gas prices, and lower average real GDP growth. The effects of other variables, like higher heat rates, would be expected to be associated with higher electricity prices in the Category C jurisdictions, although these impacts are seemingly tempered by the apparent price-reducing impact of the lower share of natural gas-based utilization, lower natural gas prices and lower average real GDP growth in the post-restructuring period. Similarly, the rise in electricity prices in the 16 Category D jurisdictions is associated with higher shares of natural gas-based utilization, higher natural gas prices, and higher real GDP growth.

To the extent that the pre-restructuring electricity price difference is explained by exogenous factors like fuel prices and average GDP growth, and the change in electricity prices from the pre- to the post-restructuring period can be explained predominantly by the same exogenous factors, then the role of restructuring in the determination of (post-restructuring) electricity prices may appear minimal. However, it is unlikely that the entire decrease in average electricity prices in the Category C jurisdictions and the increase in average electricity prices in the Category D jurisdictions in the post-restructuring period can be solely attributed to exogenous factors. The reason is quite simple: the decrease of 2.58% in average electricity prices in the 4 Category A non-restructured jurisdictions is smaller than the 5.21% decrease observed in the 8 Category C restructured jurisdictions. Similarly, the increase in average electricity prices in the 23 Category B non-restructured jurisdictions of 8.73% exceeds the corresponding 7.7% increase in the 16 Category D restructured jurisdictions. This may suggest a role played by restructuring in lowering electricity prices, especially if the effect of the exogenous variables has been similar within the two types of jurisdictions where electricity prices fell and within the two types of jurisdictions where electricity prices increased in the post-restructuring period. This issue is examined next.

5.5.3.5 US Jurisdictions where Average Electricity Prices Fell in the Post-1996 / Restructuring Period

Information in Table 5.11 can also be utilized to discern the common attributes in the explanatory variables in the 4 non-restructured Category A jurisdictions and the 8 restructured Category C jurisdictions where average electricity prices fell. The first observation to note is that in the Category A jurisdictions, the pre-1996 average electricity prices were the lowest within the 4 categories of US jurisdictions, whereas they were highest in the Category C restructured jurisdictions. This difference between Categories A and C in the pre-restructuring / pre-1996 average electricity prices is associated with Category A having a much greater average share of coal capacity and generation, more than twice as small shares of average natural gas-based capacity and generation, lower average natural gas based utilization shares, indicating less tightness in supply, lower average fuel prices, and lower average real GDP growth, which is viewed as indicating lower electricity demand growth. All these factors potentially lowered the electricity price in the Category A jurisdictions. In contrast, the higher heat rates and higher HDDs in these jurisdictions would likely have affected electricity prices in the opposite direction, which suggests that the impact of these variables on electricity prices was more than offset by the effects of other variables, like fuel prices.

In terms of changes from the pre-1996 / pre-restructuring period to the post-1996 / post-restructuring period, electricity prices fell by 2.58% in the Category A jurisdictions and by 5.21% in the Category C jurisdictions. Some of this percentage reduction in average electricity price may be explained by the notable common changes in the two types of jurisdictions, such as the decline in natural gas-based heat rates, lower coal prices, lower real GDP growth, and lower HDD.

The impact of the increase in natural gas prices in both types of jurisdictions (which would be expected to cause electricity prices to increase), while not as large as the increase in natural gas prices in the other two categories of US jurisdictions, seem to have been eclipsed by the impact of other variables. While the changes in many of these other variables seem to be common to Category A and Category C jurisdictions, a notable difference is that the average total capacity and generation rose in Category A jurisdictions but fell in Category C jurisdictions in the post-restructuring period.

As far as the exogenous variables are concerned, the percentage changes in coal prices for categories A and C are -13.57% and -7.55%, the percentage changes for real GDP growth are -7.43% and -16.04%, and the percentage changes for HDD are -4.84% and -3.38%, respectively. Finally, the increases in natural gas prices, which are expected to affect electricity prices in the opposite direction to the changes in these other variables, is 48.17% for the category A and 63.33% for Category C. Although the greater increase in efficiency, greater decline in coal prices, and greater fall in electricity demand growth in the Category A jurisdictions would seem to indicate that there should be a greater decline in electricity prices in these jurisdictions, the observed percentage decline in electricity prices is not as large in the Category C jurisdictions. This lends further support to the notion that restructuring played a role in reducing electricity prices, either directly or through the impact of endogenous variables.

In terms of the endogenous variables, natural gas-based heat rates changed by -2.84% and -0.72%, respectively, in Category A and Category C jurisdictions. The corresponding percentage changes for coal capacity shares are -6.40% and -15.63%, and for nuclear capacity shares are -4.91% and -40.45%, respectively. Since average natural gas- and hydro-based capacities formed a small percentage of total capacity, they do not appear to be important for the analysis. However, it is interesting to note that the average coal-based utilization share rose by 20.13% in Category A jurisdictions but only by 5.85% in the Category C jurisdictions, while the corresponding increases for natural gas-based utilization were 1.43% and 13.66%.

The magnitude of changes in the endogenous variables indicates that there has been a greater efficiency increase in natural gas plants and more utilization of coal-based capacity in the Category A jurisdictions, which seems to indicate that, in terms of endogenous variables, while reliance on coal is significant for reducing electricity prices, so too is the impact of greater efficiency of natural gas plants and hence the role for technological innovation. This would seem to indicate that even in the absence of restructuring initiatives, capacity composition and efficiency-enhancing technology can reduce electricity prices.

It may also be noted that there has been a greater reduction in the share of nuclear-based capacity and greater utilization share of natural gas-based capacity in the Category C jurisdictions. While it may be tempting to attribute these changes to restructuring, in the 23 Category B jurisdictions that did not restructure (and where electricity prices increased after 1996), natural gas-based utilization shares increased by an even greater amount (59.11%), indicating that a greater utilization of natural gas plants is not a distinguishing characteristic of restructured jurisdictions. The decline in the nuclear capacity share, however, is only -10.79% in the Category B jurisdictions, which seems to indicate that perhaps the greater -40.45% change in the nuclear capacity share in the 8 restructured Category C jurisdictions is in fact a result of restructuring initiatives.

Given that there is a greater percentage decline in electricity prices in the 8 restructured Category C jurisdictions, and that changes in the exogenous variables would lead one to expect a greater decline in electricity prices in the 4 Category A non-restructured jurisdictions, as would changes in many of the endogenous variables, the only variable that would seem to clearly indicate the opposite conclusion – of a greater decline in electricity prices in the 8 restructured Category C jurisdictions – would be the nuclear capacity share. To the extent that the greater decline in this share is an outcome of restructuring initiatives, this would indicate that through the change in the composition of generation capacity – specifically nuclear capacity – restructuring initiatives have managed to reduce electricity prices. However, pinning the entire price differential on just one variable is suspect, and hence an analysis of both types of jurisdictions where electricity prices increased is warranted in order to investigate the extent to which it appears reasonable to attribute the greater electricity price decrease observed in Category C jurisdictions to restructuring.

5.5.3.6 US Jurisdictions where Average Electricity Prices Rose in the Post-1996 / Restructuring Period

The final set of comparisons is between the two types of US jurisdictions where electricity prices rose in the post-1996 / post-restructuring period (Category B and Category D). This is of interest because while average electricity prices rose in both of these categories of jurisdictions, the increase has been greater in the 23 non-restructured Category B jurisdictions, which may be indicative of the electricity price dampening role of restructuring.

In terms of exogenous variables, natural gas prices increased by 83.35% between the two periods in the 16 Category D jurisdictions, but only by 55.48% in the Category B jurisdictions (Table 5.11). The level of the natural gas price is also marginally higher in the Category D jurisdictions in the post-restructuring period. Coal prices are lower in this period in the Category B jurisdictions, which also exhibit a greater percentage decline in coal prices between the two periods. Based just the level and changes in fuel prices, this suggests that a greater increase in electricity prices might have been expected in the 16 restructured Category D jurisdictions. Likewise, the level and percentage increase in real GDP growth, and hence increase in growth electricity demand, is greater for Category D than Category C, again possibly suggestive of the expectation of a greater price increase in the 16 restructured jurisdictions.

The data on HDDs indicate that while HDDs fell by a greater percentage in the Category B jurisdictions, indicating a price-reducing impact there, the initial levels of HDDs were actually lower in the restructured jurisdictions. However, the post-1996 / post-restructuring average HDD is similar for both types of jurisdictions, so it appears that HDD cannot explain the differences in electricity prices. Overall, based on levels and changes in the exogenous variables, it likely would have been expected that electricity prices would have increased more in the 16 Category D jurisdictions that restructured than in the 23 Category B jurisdictions that did not.

As far as the endogenous variables are concerned, the share of coal-based capacity is about 10 percentage points higher in the Category B jurisdictions, and this difference is maintained subsequent to restructuring. The lower share of coal-based capacity and the greater percentage decrease in that capacity share in the Category D jurisdictions would suggest that a greater electricity price increase might have been expected there. Similarly, a greater natural gas-based capacity share and gas-based capacity utilization in the Category D jurisdictions would seem to lend further support to this expectation.

On the other hand, lower average natural gas- and coal-based heat rates in the Category D jurisdictions would be expected to have worked towards reducing electricity prices in the 16 restructured jurisdictions. Interestingly, it appears that this difference in efficiency cannot be attributed to restructuring because the percentage decline between periods in natural gas-based heat rates is similar in both types of jurisdictions, -9.63% and -10.44% for Category B and Category D jurisdictions, respectively. Coal-based heat rates actually increased in category D, although the average level of these heat rates is still lower in those jurisdictions than for those in Category B. This indicates that lower levels of heat rates cannot be attributed to restructuring initiatives that might have impacted any technological change.

Turning to hydro- and nuclear-based capacity, nuclear capacity shares fell greatly (-25.85%) between periods in the 16 restructured Category D jurisdictions compared to the -10.79% percentage change in the Category B jurisdictions. While it is tempting to attribute the huge declines in nuclear based capacity shares to restructuring, it is notable that the shares of nuclear capacity are similar in both categories of jurisdictions (10.81% and 9.52% in the post-1996 /post-restructuring period for Category B and Category D jurisdictions, respectively). Similarly, while there is a large increase in the hydro-based capacity share in the Category D jurisdictions in the post-restructuring period, the share of hydro capacity in the Category D jurisdictions in the post-restructuring period is 20.29% compared to 15.75% (in the post-1996 period) for the Category B jurisdictions.

To the extent that restructuring contributes to the 5 percentage point higher hydro capacity share and the slightly lower nuclear capacity share in the post-1996 / post-restructuring period, the lower increase in electricity prices for

Category D jurisdictions by 1.02 percentage points (8.72% – 7.70%) may be attributed to restructuring initiatives. This suggestion seems to lend support to a similar finding obtained in the context of the comparison of Category A and Category C jurisdictions where prices fell in the post-1996 / post-restructuring period (Section 5.5.3.5). Unfortunately, this is not definitive, and in any event is of little direct help in the context of Alberta which has no nuclear capacity or generation. In order to determine which of the findings from this examination of US jurisdictions may be of relevance to Alberta, and to determine whether information from any of these jurisdictions, either by itself or in conjunction with other jurisdictions, may be useful for modifying the values of the endogenous variables for Alberta in its post-restructuring period, in the next section information on the relevant variables will be compared for Alberta and the various US jurisdictions.

5.6 Comparison of Alberta with US Jurisdictions

Now that the behaviour of electricity prices as well as various exogenous and endogenous variables that might explain this behaviour has been examined for the various regulated and non-regulated US jurisdictions, the next step is to compare US information with information pertaining to Alberta. We begin with a comparison of the behaviour of electricity prices in the various US jurisdictions with electricity prices in Alberta, and then turn to a consideration of the exogenous and endogenous variables.

5.6.1 Alberta and US Electricity Prices

For Alberta, the electricity price in units of Canadian cents/kWh is obtained from Electric Power Statistics (*EPS*), and is computed by dividing revenue received by the quantity of energy sold. These prices are available annually from 1960 to 2007. The EPS data refer to revenue received and energy sold by electric utilities and industrial establishments in conjunction with domestic and farm businesses. As described in Section 5.4.1, electricity prices for the 51 US jurisdictions in units of US cents/kWh were obtained from the Energy Information Administration *EIA*, US DOE web site for the annual period 1990 to 2004. In order to facilitate comparison with the Alberta electricity prices, which were not separable between electricity utilities and industrial establishment, we have used US residential electricity prices based on the total electric industry classification.

Market restructuring is considered at the retail level, because our objective is to study the impact of electricity market restructuring on residential consumers. However, while analyzing the US data, a distinction was made between the restructuring legislation date and the date for implementation of retail access. The restructuring legislation date was considered as the cutoff point for defining the pre- and post-restructuring periods in order to facilitate the analysis for the difference of means test. Use of the date for retail access as a cutoff point to distinguish the two periods was not feasible because that would have left very few or no data points for the post-restructuring period. In Alberta, electricity market restructuring was implemented at the wholesale level in 1996, whereas it was implemented at the retail level in 2001. In order to be consistent with the US data analysis and to facilitate the difference of means test analysis, the year 1996 is used to distinguish between the pre- and post-restructuring periods. However, alternative difference of means test results that are obtained for Alberta when the year 2001 is used to distinguish the two periods are also reported.

Table 5.12 provides the test results and information underlying the difference of means test analysis in the context of Alberta. The information in this table indicates that average electricity prices increased by 25.11% from the pre restructuring to the post-restructuring period, and that this change is statistically significant even at 1% level of significance. Among US jurisdictions that restructured, based on the information in Table 5.12 this price increase is on a par with those experienced by Oregon and Nevada where, given distinguishing years of 1999 and 1997, respectively, average electricity price increases of 24.36% and 25.88% are also statistically significant at a 1% level of significance. In the context of non-restructured jurisdictions, this price increase is similar to that of the statistically significant 24.66% price increase in the state of Vermont.

Table 5.12: Significance of Change in Average Residential Electricity Price between the Pre- and Post-Restructuring Periods for Alberta

Average Electricity Prices		
Restructuring date	**1996**	**2001**
Pre Restructuring	7.71	8.03
Post Restructuring	9.64	10.51
% change	25.11%	30.88%
n_1	6	11
n_2	12	7
df	16	16
n_h	8.00	8.56
s_1^2	0.4319	0.3827
s_2^2	1.4642	0.5421
MSE	0.9480	0.4624
s	0.4868	0.3288
M_2-M_1	1.94	2.48
t [t* (α=0.05) = 2.18]	3.97**	7.54**

** Significant at 1% level of significance

Of course, a more detailed analysis is required to identify which US jurisdiction most closely mimics the trend in Alberta electricity prices. Table 5.13 presents a correlation analysis between the electricity prices in Alberta and both types of US jurisdictions from 1990 – 1995.[29] This table also includes the absolute difference between average electricity prices in Alberta and in each of the 51 US jurisdictions in order to identify the US jurisdiction whose average electricity price from 1990-1995 was most similar to Alberta electricity price levels during that period.

Table 5.13 indicates that, based on correlation of electricity prices between 1990 and 1995, among restructured states electricity prices in New Mexico most closely mimic the trend in Alberta electricity prices. However, according to difference of means tests in Tables 5.7 and 5.12, Oregon and Nevada seem to depict the rise in electricity prices in Alberta in the post-restructuring period most appropriately. The increase in Alberta electricity prices in the post-restructuring period is 25.11%, compared with 24.36% and 25.88% in Oregon and Nevada, respectively. Correlation analysis, on the other hand, indicates that New Mexico prices from 1990-1995 have a correlation of 0.78 with Alberta electricity prices, whereas Oregon and Nevada have correlations of 0.11 and 0.23, respectively, with Alberta electricity prices over the same period.

In terms of the absolute differences shown in Table 5.13, neither New Mexico nor Oregon electricity prices are as similar to Alberta electricity price levels as electricity prices for Nevada or some of the other US jurisdictions that restructured. The analysis also indicates that there are much stronger correlations for two of the non-restructured jurisdictions, and in terms of absolute differences, four non-restructured jurisdictions seem to match Alberta better than do any of the restructured jurisdictions. This might appear to suggest that the Alberta electricity market is more in line with the markets in non-restructured jurisdictions than in restructured ones. However, this is only based on electricity prices, and a different conclusion may be reached once the values of various other explanatory variables are also compared.

Finally, an examination of the correlations between electricity prices and various fuel prices, displayed in Table 5.14, is suggestive about the extent to which it might be appropriate to ascribe the change in electricity prices to restructuring. It might be expected that the correlation between electricity prices and the respective fuel prices, whether large or small, would be positive. However, for several US jurisdictions, both restructured and non-restructured, the respective correlations are negative. In the context of restructured jurisdictions, a negative correlation may imply the role of a third factor like restructuring affecting the relationship between electricity prices and the respective fuel prices. However, because these negative correlations also exist in the context of non-restructured jurisdictions, the role of restructuring in terms of its impact on electricity prices may be masked by other factors like technological progress.

[29] The pre-restructuring period for Alberta, 1990 – 1995, as defined by the date of wholesale market restructuring, was selected as the period for the analysis. This also works well for the US jurisdictions as the earliest year in which any jurisdiction passed its restructuring legislation was 1996.

This again indicates the importance of using a regression-based framework to examine the role of restructuring on electricity prices in order to allow this role to be separated from the effects of changes in various other variables.

Table 5.13: Correlation and Absolute Differences of Electricity Prices between Alberta and US Jurisdictions from 1990 – 1995

Restructured Jurisdictions				Non-restructured Jurisdictions			
	CORR		**AVG DIFF**		**CORR**		**AVG DIFF**
NM	0.782	MT	0.31	AL	0.949	WY	0.11
OK	0.721	NV	0.48	FL	0.882	ND	0.17
TX	0.676	DC	0.80	MS	0.633	WV	0.18
RI	0.657	OK	0.84	LA	0.631	NE	0.19
AZ	0.656	OR	1.07	NC	0.602	TN	0.36
DE	0.586	VA	1.44	AK	0.559	KY	0.43
MA	0.546	TX	1.59	WI	0.537	AL	0.58
MD	0.539	MD	1.90	MN	0.440	IN	0.65
CA	0.526	AR	2.01	GA	0.433	WI	0.77
AR	0.513	MI	2.01	HI	0.351	UT	0.86
DC	0.421	OH	2.21	WV	0.298	MS	0.87
PA	0.419	DE	2.66	VT	0.240	SD	0.90
CT	0.412	NM	2.93	CO	0.226	MN	0.90
NJ	0.399	AZ	3.18	SC	0.209	CO	1.10
MI	0.393	PA	3.43	ND	0.127	ID	1.11
NY	0.387	IL	4.00	IA	0.125	SC	1.20
ME	0.348	MA	4.55	SD	0.102	MO	1.21
IL	0.305	RI	4.90	KY	0.088	LA	1.37
NH	0.273	CA	4.91	WA	0.061	WA	1.50
MT	0.266	CT	4.94	ID	0.032	GA	1.55
OH	0.259	NJ	5.04	TN	0.026	FL	1.71
NV	0.229	ME	5.11	KS	-0.025	KS	1.75
VA	0.195	NH	5.68	NE	-0.174	IA	1.87
OR	0.111	NY	6.62	WY	-0.302	NC	1.94
				MO	-0.372	VT	3.66
				UT	-0.604	AK	4.76
				IN	-0.868	HI	5.50

Note: Exchange rate conversions are made using CANSIM series V37426, which provides the monthly noon spot rate between Canada and the US.

Table 5.14: Correlation of Electricity Prices with Coal and Natural Gas Prices for the 51 US Jurisdictions, 1990-2004

Jurisdiction	Electricity and coal prices	Electricity and natural gas prices	Coal and natural gas prices	Jurisdiction	Electricity and coal prices	Electricity and natural gas prices	Coal and natural gas prices
Restructured Jurisdictions				**Non-restructured Jurisdictions**			
Arizona	0.7175	-0.6710	-0.7458	Alaska		0.7173	
Connecticut	-0.6761	-0.2091	-0.2917	Alabama	-0.6974	0.8312	-0.7555
Delaware	-0.5637	-0.3441	0.1595	Colorado	-0.4607	0.8055	-0.6644
District of Columbia				Florida	0.2105	0.8375	-0.0780
Illinois	0.8684	-0.7827	-0.7598	Georgia	-0.0369	0.0472	-0.0246
Maine				Hawaii			
Maryland	-0.4398	-0.3326	-0.7651	Iowa	-0.7599	0.8363	-0.5052
Massachusetts	0.0480	0.4394	0.4666	Idaho			
Michigan	-0.7055	0.1570	-0.7502	Indiana	-0.3511	0.5268	-0.5577
New Hampshire	-0.5583	-0.1546	0.3871	Kansas	0.4951	-0.5296	-0.3930
New Jersey	-0.3031	-0.3917	0.2612	Kentucky	0.9553	-0.7801	-0.6239
New York	-0.4965	0.5859	0.2933	Louisiana	-0.2419	0.6486	-0.8037
Ohio	-0.0839	0.0340	-0.5814	Minnesota	-0.8045	0.8297	-0.5923
Oregon	0.5752	0.7631	0.5205	Missouri	0.8994	-0.7874	-0.5975
Pennsylvania	-0.1155	0.0898	-0.5043	Mississippi	0.2414	0.7553	-0.1108
Rhode Island		0.3033		North Carolina	0.5303	0.5123	0.1332
Texas	0.3291	0.9071	0.1940	North Dakota	0.4709	0.9102	0.3696
Virginia	0.4835	0.3990	0.2871	Nebraska	-0.5961	0.8964	-0.5632
Arkansas	0.7050	-0.7452	-0.7588	South Carolina	0.2980	0.5319	-0.7900
Montana	-0.5222	0.2950	-0.0369	South Dakota	0.8111	-0.1854	-0.3142
Nevada	-0.4134	0.8250	-0.4610	Tennessee	-0.4491	-0.3283	-0.1385
New Mexico	-0.4816	-0.6919	0.5393	Utah	0.4629	-0.2052	-0.2343
Oklahoma	0.0290	0.7062	-0.1771	Vermont		0.8692	
California		0.5820		Washington	0.3726	-0.0952	0.6820
				Wisconsin	-0.4914	0.8305	-0.5041
				West Virginia	-0.5967	-0.1784	-0.0504
				Wyoming	0.1769	-0.2793	0.0183
AVERAGE	-0.0802	0.0802	-0.1362	**AVERAGE**	0.0191	0.3207	-0.3086
US	-0.4386	0.7718	-0.4345				

5.6.2 Explanatory Variables in Alberta and US Jurisdictions

The analysis in the preceding sections has shown that restructuring initiatives are neither necessary for reducing electricity prices, as shown by the 4 (Category A) non-restructured US jurisdictions, nor sufficient, as shown by the 16 (Category D) restructured US jurisdictions where electricity prices increased after restructuring. Increases in efficiency through a decline in heat rates were also not found to be specifically associated with US restructuring initiatives. Similarly, it was determined that the decline in electricity prices in the 8 Category C US jurisdictions that restructured was associated with a decline in average real GDP growth, a reduction in natural gas capacity share and a lower natural gas price increase compared to the other 16 US jurisdictions that restructured but where electricity prices increased in the post restructuring period (Category D). However, at least two of these factors – lower natural gas price increase and a decline in real GDP growth – were also evident in the Category A non-restructured jurisdictions where electricity prices decreased.

Against this broader context of US jurisdictions, data on the explanatory variables for Alberta, and how they have changed between the pre- and post-restructuring period, are examined in order to determine which of these types of US jurisdictions is most similar to Alberta.

So far as the capacity share mix is concerned, in the pre 1996 / restructuring period the coal capacity share is higher in the non-restructured US jurisdictions (61.34%) than in the restructured US jurisdictions (37.61%), predominantly because of the 4 jurisdictions that did not restructure but where electricity prices fell post 1996 (Category A in Table 5.11). In terms of the coal share of capacity, Alberta seems closer to the non-restructured jurisdictions in general, and to these 4 jurisdictions in particular. In all four types of jurisdictions shown in Table 5.11, as well as in Alberta, the coal capacity share fell in the post 1996 / restructuring period, with the greatest changes occurring in Alberta and in the 8 jurisdictions that restructured and experienced electricity price decreases (Category C). The important point to note is that while the coal-based capacity share fell in all four categories of US jurisdictions and in Alberta, the share of coal-based capacity in Alberta and in the non-restructured jurisdictions, especially the four in Category A, remained higher than in the restructured jurisdictions.

Hydro capacity share percentages for the pre-1996 / pre-restructuring period are similar for the restructured and non-restructured jurisdictions as well as for Alberta, although the hydro capacity share is much lower in both types of jurisdictions where electricity prices fell. In the post-restructuring period the hydro capacity share rises in the restructured jurisdictions, whereas it falls slightly in the non-restructured jurisdictions. Alberta is similar to the non-restructured jurisdictions in this regard. The important point to note here appears to be the greater increase in the hydro capacity share in the restructured jurisdictions subsequent to restructuring.

The nuclear capacity share is more than twice as high in the restructured jurisdictions when compared to the non-restructured jurisdictions, whereas there is no nuclear capacity in Alberta. While the nuclear capacity share falls in both types of jurisdictions, there is a larger decline in the restructured jurisdictions, which suggests that it may be an outcome of the restructuring initiatives.

For the pre-1996 / restructuring period, the natural gas capacity share is more than twice as high in the restructured jurisdictions (8.26%) than in the non-restructured jurisdictions (3.20%). There is a greater increase in the natural gas capacity share in the non-restructured jurisdictions compared to those that restructured, although natural gas capacity shares are higher in the latter jurisdictions. The natural gas-based capacity share in Alberta is much higher than in either type of US jurisdiction, although like the non-restructured jurisdictions, natural gas-based capacity shares rose greatly in Alberta in the post restructuring period. The increase in natural gas-based capacity shares in the non-restructured jurisdictions suggests that natural gas-based capacity shares would likely have increased even in the absence of restructuring initiatives.

In summary, the analysis on the capacity share mix indicates that, although Alberta has no nuclear-based capacity, it is similar to the non-restructured jurisdictions in terms of its high share of coal-based capacity, and the changes in the shares of natural gas-based and hydro-based capacity in Alberta have been similar to the changes in the shares in natural gas-based and hydro based capacity in the non-restructured jurisdictions.

Data on the generation share mix in Table 5.11 are similar to those described above pertaining to the capacity share mix, although from the pre-restructuring to the post-restructuring period, Alberta experienced a much greater decline in coal-based generation than in any of the four categories of US jurisdictions, and a much greater increase in natural gas-based generation. Total fuel consumption in Alberta increased, as it did also in the non-restructured jurisdictions, although it fell in the restructured jurisdictions. So far as the coal – natural gas mix of fuel consumption is concerned, average natural gas consumption increased while coal consumption fell for both categories of non-restructured jurisdictions. While these findings, also evident in Alberta, are consistent with a shift from coal to natural gas-based generation, in the 16 jurisdictions that restructured and where electricity prices rose in the post-restructuring period (Category D), natural gas consumption actually fell. Overall, however, there is no common pattern in the consumption or generation data in Table 5.11 in terms of indicating whether a greater or lower coal-natural gas consumption or generation ratio is associated with a decreasing impact on electricity prices.

Coal and natural gas-based utilization, which measure the tightness of supply from coal and natural gas-based plants, respectively, increased in Alberta as well as in all four categories of jurisdictions. Utilization figures for Alberta are much higher than the averages for both types of US jurisdictions. While coal-based utilization is similar for both types of US jurisdictions, natural gas-based utilization is higher in the restructured jurisdictions.

Coal- and natural gas-based heat rates are lower in the restructured jurisdictions, indicating a greater efficiency of coal and natural-gas based plants in those jurisdictions. Natural gas-based heat rates have fallen in both types of jurisdictions as well as in Alberta, although more so in the non-restructured jurisdictions, which indicates that any changes in technology that have impacted efficiency of the plants are not necessarily associated with restructuring initiatives. Natural gas-based heat rates in Alberta are much lower, which indicates a greater efficiency of natural gas-based plants.

The above analysis of the endogenous explanatory variables indicates that in terms of capacity and generation, Alberta is more similar to the non-restructured jurisdictions, specifically those where electricity prices fell in the post 1996 period. It also suggests that restructuring initiatives are not essential for improvements in plant efficiency. Since Alberta has little hydro-based capacity and no nuclear-based capacity, other observed outcomes of the US restructuring initiatives, particularly changes in the percentages of hydro and nuclear-based capacity and generation, are not particularly relevant in the context of Alberta.

The greater change in the coal-based capacity share in Alberta and in the restructured jurisdictions suggests one common outcome of the restructuring initiatives. However, while coal-based capacity shares fell in the 8 Category C restructured jurisdictions, natural gas-based capacity shares also fell for these jurisdictions, whereas in Alberta the natural gas-based capacity share increased, just as in the non-restructured jurisdictions. Indeed, this difference may provide a partial explanation of why electricity prices in those 8 jurisdictions fell whereas electricity prices increased in Alberta in the post-restructuring period.

Comparisons of the exogenous variables for the US and Alberta can help indicate whether external conditions in the Alberta electricity market were similar to those in the restructured or non-restructured US jurisdictions. Since the comparisons in this case involve the use of prices and dollar amounts, Alberta data were converted to units of US equivalents by using the Canada-US exchange rate. The average monthly noon spot rate in Canadian dollars from CANSIM series V37426, available from 1950 onwards, was used for this purpose. Monthly exchange rates were converted to an annual basis, and the resulting annual exchange rate was used to convert Alberta natural gas and coal prices, real GDP and wages to units based on US dollars.

The fuel price data indicate that both coal and natural gas prices are much lower in Alberta compared to both types of US jurisdictions. While natural gas prices increased across both types of US jurisdictions and in Alberta, there has been a general decline in coal prices. In particular, there has been a greater decline in coal prices in the non-restructured jurisdictions and a greater increase in natural gas prices in the restructured jurisdictions. Generally, fuel prices are greater in the restructured jurisdictions than in non-restructured jurisdictions, and in terms of the four subcategories of jurisdictions in Table 5.11, fuel prices are greater in the Category B and Category D jurisdictions that experienced electricity price increases than in the Category A and Category C jurisdictions that experienced electricity price decreases. While fuel prices in Alberta are lower than those in the US jurisdictions, the percentage decline in Alberta coal prices is much smaller than in all four categories of US jurisdictions, while the percentage increase in Alberta natural gas prices is much higher than in all US jurisdictions except those in Category D.

This information on fuel prices, when viewed in the context of the capacity share mix, indicates clearly why electricity prices would have been lower in jurisdictions which are heavily dependent on coal-based generation, as in the Category A jurisdictions, or where there has been a greater decline in the natural gas capacity share, as in the Category C jurisdictions. While fuel price levels are lower in Alberta than in the US, based on this analysis the greater increase in natural gas prices and in natural gas-based capacity share experienced in Alberta would be expected to be associated with increasing electricity prices.

As far as the demand variables are concerned, both the increase in real GDP growth and higher levels of HDDs indicate a higher electricity demand in Alberta.[30] The data also indicate that in the US jurisdictions where electricity prices fell, the HDD levels have been lower and the real GDP growth has declined as compared to the jurisdictions where electricity prices increased in the post 1996 / restructuring period. This indicates a very clear role of the demand variables in explaining the direction of change in the electricity price.

To summarize, on the basis of having higher coal-based shares of both generation and capacity, Alberta seems to be most similar to the 4 non-restructured US jurisdictions where electricity prices fell in the post restructuring period (Category A). However, Alberta has a much higher natural gas-based share of capacity and generation as well, while having no nuclear based capacity at all and only a small percentage of hydro based capacity. This means that any role of restructuring related to nuclear and hydro based capacity in the US are essentially irrelevant in the context of Alberta. While Alberta has a higher natural gas-based share of capacity and generation, its efficiency of natural gas-based plants is also higher given the much lower natural gas-based heat rates, and while Alberta has lower fuel prices, the increase in natural gas prices has been quite high, along with a higher electricity demand growth.

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[30] It may be noted that while CDDs may have a similar or even greater effect on electricity demand in the US than HDDs, as noted earlier in Section 5.4.7, CDDs are ignored and US jurisdictions are compared on the basis of HDDs, since the eventual objective is to determine jurisdictions that are similar to Alberta where HDDs retain a greater importance.

On the other hand, the percentage decline of 15.90% in the coal-based capacity share in Alberta was similar to the percentage decline of 15.63% in the 8 Category C jurisdictions that restructured and where electricity prices fell post restructuring. However, in those 8 jurisdictions, the natural gas capacity share decreased by 40.45% in the post restructuring period, while average real GDP growth also fell in the post restructuring period, whereas Alberta experienced an increase in the natural gas capacity share and an increase in real GDP growth.

While it is clearly debatable from the above analysis as to which type of jurisdiction best matches Alberta, a serious drawback of this type of analysis for this purpose is that it makes use of average figures in the pre and post 1996 / restructuring period for comparison purposes, and this may mask a lot of information. Therefore, in Section 5.7, the explanatory variables in Alberta and the two types of US jurisdictions will be compared using all the data points from 1990 – 2004. Absolute differences between the explanatory variables for Alberta and for all the restructured and non-restructured US jurisdictions will be computed to ascertain which of each type of jurisdiction mimics Alberta the best. Once those jurisdictions are identified, the differences between the values of the endogenous variables in the different jurisdictions will be used to modify the values of the Alberta endogenous variables, as explained in Section 5.9.1, in order to determine counterfactual values of the endogenous variables, that is, values that the endogenous variables in Alberta would have taken in the absence of restructuring. These new values will help in modifying the regression forecasts computed in Chapter 4 and hence in providing counterfactual post-restructuring electricity prices in Alberta.

5.7 Determining Jurisdictions that Did and Did Not Restructure their Electricity Market and which are Similar to Alberta

In what follows, absolute differences (and in some cases correlations) between the explanatory variables for Alberta and for all the restructured and non-restructured jurisdictions are computed to ascertain which two jurisdictions – one that restructured and one that did not – are most similar to Alberta. Once those jurisdictions are identified, as explained in Section 5.9.1, differences between the values of the endogenous variables in different time periods will be used to modify the values of the endogenous variables in Alberta in its post-restructuring period to obtain counterfactual values of these variables, that is, values that they might have taken in the absence of restructuring. These new values are used in Section 5.10.1 to modify the regression forecasts computed in Chapter 4, and hence provide counterfactual electricity prices in Alberta in the post-restructuring period.

Based on the analysis in the preceding sections, there are a variety of explanatory variables to be considered. Endogenous variables, those that may have been affected by restructuring, include capacity, generation, consumption, utilization ratios and heat rates for various fuels, while exogenous variables reflect fuel prices (coal prices, gas prices), electricity demand (real GDP, real GDP growth, HDD) and operating costs (annual wage / worker).[31] Comparisons of jurisdictions are based on the average size of absolute differences between Alberta and both types of jurisdictions for select endogenous variables for the pre-restructuring period from 1990 to 1995 – coal, gas, hydro and nuclear based capacity and generation shares – and for select exogenous variables for the 1990–2004 period – heating degree days, the GDP growth rate, coal and natural gas prices. While absolute differences reflect proximity in variables, in some cases – particularly with fuel prices – information on the trend is also useful, so correlations for fuel prices are also computed. For the purposes of facilitating comparisons between Alberta and the US, Alberta coal and natural gas prices were converted to US currency by using average yearly exchange rates based on the monthly average noon spot exchange rate provided by the CANSIM series V37426.

For illustration purposes, these computations for Alberta and Arizona are presented in Table 5.15 below. Similar analyses are conducted for all the other jurisdictions. Jurisdictions are ranked in ascending order on the basis of average absolute differences with Alberta, and in descending order on the basis of the correlations. This ranking analysis is done separately for restructured jurisdictions, as shown in Table 5.16, and non-restructured jurisdictions (not shown).

[31] An additional variable that is included in the model but not listed here is the interest rate, or some alternative measure of the cost of capital. A cost of capital proxy is excluded due to limitations in the variability of interest rates over jurisdictions and in the availability of data on alternative proxies.

Table 5.15: Sample Computation of Absolute Differences for the Alberta Pre-Restructuring Period 1990 – 1995 for Select Endogenous Variables and of Absolute Differences and Correlations for 1990 – 2004 for Select Exogenous Variables, between Alberta and Arizona

Year	Endogenous Variables (shares)							
	Capacity				Generation			
	Coal based	Natural gas based	Hydro based	Nuclear based	Coal based	Natural gas based	Hydro based	Nuclear based
1990	38.48	13.88	4.38	25.52	37.40	2.76	6.71	33.07
1991	38.13	14.37	4.50	25.54	41.15	2.22	5.13	37.59
1992	31.13	22.35	5.95	25.36	31.56	11.57	6.12	36.53
1993	31.17	22.18	5.96	25.32	25.92	13.18	6.16	32.41
1994	31.96	21.42	6.25	25.24	27.57	12.39	6.95	32.54
1995	31.95	21.99	6.28	25.23	35.86	11.41	8.15	39.13
1996								
1997								
1998								
1999								
2000								
2001								
2002								
2003								
2004								
Average 1990-1995	33.80	19.36	5.55	25.37	33.24	8.92	6.54	35.21
Average 1990-2004								
Correlation 1990-2004								

…continued

Table 5.15 (continued)

Year	Exogenous Variables			
	Real GDP growth	HDD	Natural gas price	Coal price
1990			0.93	1.07
1991	0.69		0.69	0.99
1992	6.43		1.05	0.98
1993	2.14	3,149	1.12	0.95
1994	2.01	3,209	0.66	0.98
1995	4.86	3,752	0.52	1.02
1996	5.47	4,480	1.59	1.05
1997	1.87	3,112	1.40	1.04
1998	4.15	2,874	0.88	0.96
1999	5.83	3,204	0.60	0.97
2000	0.60	3,575	1.64	0.85
2001	1.13	2,925	2.12	0.87
2002	0.24	3,452	0.52	0.89
2003	1.49	3,585	1.04	0.82
2004	0.07	3,428	1.43	0.82
Average 1990-1995				
Average 1990-2004	2.64	3,395	1.08	0.95
Correlation 1990-2004			0.927	-0.125

Table 5.16: Sample Sorting of Correlation for 1990 -2004 and Absolute Differences for the Alberta Pre–Restructuring Period 1990 – 1995 for Restructured US jurisdictions for Select Endogenous and Exogenous Variables

Select Endogenous Variables (shares)							
Coal based capacity		Natural gas based capacity		Hydro based capacity		Coal based generation	
New Mexico	9.67%	New Jersey	2.81%	New Hampshire	0.72%	Ohio	6.42%
Michigan	14.67%	New York	6.49%	New York	1.29%	New Mexico	6.48%
Ohio	16.05%	Texas	6.61%	Arkansas	1.32%	Nevada	7.29%
Pennsylvania	16.43%	Maryland	7.86%	Oklahoma	4.98%	Michigan	11.20%
Nevada	17.72%	Delaware	8.00%	Maine	5.43%	Maryland	22.08%
Montana	18.18%	New Mexico	8.33%	Virginia	5.54%	Montana	22.70%
Illinois	21.84%	Oklahoma	14.24%	Arizona	5.55%	Delaware	23.72%
Delaware	25.30%	Illinois	16.20%	Maryland	6.03%	Pennsylvania	23.94%
Maryland	26.34%	Nevada	16.96%	Massachusetts	8.28%	Oklahoma	24.31%
Arkansas	28.27%	Massachusetts	17.75%	Pennsylvania	8.55%	Arkansas	32.29%
Oklahoma	30.35%	Virginia	18.16%	Nevada	8.61%	Arizona	33.24%
Arizona	33.80%	Oregon	18.94%	Connecticut	8.76%	Texas	34.31%
Virginia	36.48%	Michigan	19.06%	Michigan	8.86%	Virginia	38.32%
Texas	37.85%	Ohio	19.33%	New Mexico	9.32%	Illinois	41.17%
New Hampshire	45.07%	California	19.35%	Rhode Island	9.41%	Massachusetts	48.87%
Massachusetts	50.36%	Arizona	19.36%	Texas	9.41%	New Hampshire	58.76%
New York	56.23%	Montana	19.60%	Ohio	9.92%	New York	63.40%
New Jersey	56.53%	Pennsylvania	19.94%	California	10.30%	New Jersey	66.95%
Oregon	62.82%	Connecticut	20.00%	Illinois	10.31%	Connecticut	75.70%
Connecticut	62.84%	Arkansas	20.35%	Delaware	10.34%	Oregon	76.99%
District of Columbia	68.39%	District of Columbia	20.98%	District of Columbia	10.34%	District of Columbia	83.64%
Maine	68.39%	Maine	20.98%	New Jersey	10.34%	Maine	83.64%
Rhode Island	68.39%	New Hampshire	20.98%	Montana	36.54%	Rhode Island	83.64%
California	68.39%	Rhode Island	30.65%	Oregon	70.52%	California	83.64%

…continued

Table 5.16 (continued)

Select Endogenous Variables (shares)				Select Exogenous Variables			
Natural gas based generation		Hydro based generation		HDD		Real GDP growth	
Nevada	4.42%	Maryland	1.10%	New Jersey	269	Illinois	1.73%
New Mexico	5.25%	Massachusetts	1.59%	Rhode Island	379	Virginia	1.73%
New Jersey	5.35%	Virginia	1.91%	Pennsylvania	466	Texas	1.73%
Massachusetts	5.62%	Michigan	2.30%	Oregon	470	Rhode Island	1.82%
New York	5.63%	Oklahoma	2.43%	New York	498	Montana	1.87%
Arkansas	6.29%	Connecticut	2.65%	Ohio	503	Pennsylvania	1.91%
Oregon	8.15%	Pennsylvania	2.83%	Connecticut	567	Maryland	1.98%
Arizona	8.92%	New Mexico	3.20%	Michigan	582	New Jersey	2.00%
Virginia	9.15%	Texas	3.28%	Maryland	761	Oklahoma	2.02%
Maryland	9.36%	Ohio	3.93%	Illinois	783	Maine	2.03%
Delaware	9.43%	Illinois	4.03%	Delaware	796	Ohio	2.14%
Connecticut	9.84%	Delaware	4.07%	Massachusetts	827	Connecticut	2.27%
Illinois	11.01%	District of Columbia	4.07%	New Mexico	877	Massachusetts	2.28%
Michigan	11.18%	New Jersey	4.07%	Virginia	999	Arkansas	2.40%
New Hampshire	11.66%	Rhode Island	4.07%	Nevada	1,605	New York	2.45%
Pennsylvania	11.68%	New Hampshire	4.73%	Oklahoma	1,775	Nevada	2.45%
Ohio	11.98%	Arkansas	5.41%	New Hampshire	2,004	New Hampshire	2.56%
Montana	12.01%	Nevada	5.65%	Arkansas	2,008	Arizona	2.64%
District of Columbia	12.15%	Arizona	6.54%	Montana	2,570	Oregon	2.65%
Maine	12.15%	California	19.30%	Maine	2,638	California	2.65%
Oklahoma	22.26%	New York	19.50%	California	2,902	Michigan	2.86%
Texas	28.26%	Maine	23.43%	Arizona	3,395	Delaware	3.06%
California	28.91%	Montana	34.55%	Texas	3,931	New Mexico	3.31%
Rhode Island	48.37%	Oregon	80.82%	Distr. of Columbia		Distr. of Columbia	3.41%

…continued

Table 5.16 (continued)

Select Exogenous Variables							
Natural gas price				Coal price			
Average Absolute differences		Correlation 1990-2004		Average Absolute differences		Correlation 1990-2004	
Oregon	0.36	New York	0.982	Montana	0.22	Virginia	0.682
Michigan	0.58	Rhode Island	0.976	California	0.31	Texas	0.673
New Hampshire	0.67	Illinois	0.972	Oklahoma	0.52	Maryland	0.605
New Mexico	0.69	Maryland	0.971	Oregon	0.59	New Hampshire	0.598
Arkansas	0.69	Texas	0.968	Texas	0.61	New York	0.537
Texas	0.94	Virginia	0.961	Arkansas	0.83	Connecticut	0.475
Illinois	1.04	Massachusetts	0.957	New Mexico	0.86	Jersey New	0.402
Connecticut	1.07	New Jersey	0.955	Arizona	0.95	Oklahoma	0.320
Arizona	1.08	Arizona	0.927	Illinois	1.05	Nevada	0.318
New Jersey	1.10	Oregon	0.909	Michigan	1.06	Delaware	0.293
Nevada	1.15	Delaware	0.908	Nevada	1.09	New Mexico	0.183
Massachusetts	1.18	Oklahoma	0.894	Ohio	1.20	Michigan	0.136
New York	1.25	Michigan	0.892	Pennsylvania	1.23	Pennsylvania	0.125
Delaware	1.30	Arkansas	0.885	Virginia	1.42	Massachusetts	0.098
Rhode Island	1.33	New Mexico	0.881	New York	1.46	Ohio	0.049
Maryland	1.34	New Hampshire	0.814	Maryland	1.48	Arkansas	0.011
Oklahoma	1.35	Nevada	0.765	New Hampshire	1.70	Oregon	0.010
Virginia	1.36	Ohio	0.708	Delaware	1.70	Illinois	-0.089
Montana	1.64	Connecticut	0.682	Massachusetts	1.77	Arizona	-0.125
Pennsylvania	1.66	California	0.665	New Jersey	1.91	Montana	-0.357
California	1.72	Pennsylvania	0.652	Connecticut	1.98	Distr. of Columbia	
Ohio	1.74	Montana	0.632	Distr. of Columbia		Maine	
Distr. of Columbia		Distr. of Columbia		Maine		Rhode Island	
Maine		Maine		Rhode Island		California	

As can be seen from Table 5.16, the rankings for restructured jurisdictions generally differ for each variable, and the same is true of non-restructured jurisdictions. The restructured and non-restructured jurisdictions that best match Alberta based on this analysis is shown in Table 5.17.

Table 5.17: US Jurisdiction to Alberta Correspondences based on Absolute Difference and Correlation Computations for Select Variables

Select Variables	Restructured Jurisdiction	Non-Restructured Jurisdiction
Endogenous Variables (shares)		
Coal based capacity	New Mexico	Missouri
Natural gas based capacity	New Jersey	Louisiana
Hydro based capacity	New Hampshire	North Dakota
Coal based generation	Ohio	Iowa
Natural gas based generation	Nevada	Florida
Hydro based generation	Maryland	South Carolina
Exogenous Variables		
HDD	New Jersey	West Virginia
Real GDP growth	Illinois	Wisconsin
Natural gas price	Oregon	Alabama
Natural gas price (correlation)	New York	Kansas
Coal price	Montana	Nebraska
Coal price (correlation)	Virginia	Kentucky

Since these computations do not identify a unique restructured and non-restructured jurisdiction that best matches Alberta, it is necessary to focus on particular subsets of the variables and ultimately to combine them into relatively few composites in order to facilitate meaningful comparisons. Specifically, three composite variables were defined that captured capacity and generation, electricity demand, and fuel prices in order to make the task of identifying the best matching restructured and non-restructured jurisdiction more manageable. Absolute difference computations for the capacity and generation composite variable were determined by taking a weighted average of absolute differences for coal-, natural gas-, and hydro-based capacity shares, and for coal-, natural gas- and hydro-based generation shares, using the average values of coal-, natural gas- and hydro-based capacity and generation shares, respectively, for Alberta from 1990 – 1995. The resulting two weighted averages were then averaged to yield the absolute difference values for the composite generation and capacity variable. These computations were conducted separately for both restructured and non-restructured jurisdictions. For illustration purposes, Table 5.18 contains the results for the restructured jurisdictions.

Table 5.18: Weighting the Absolute Difference Computations for Generation and Capacity Shares for Restructured Jurisdictions

Restructured Jurisdiction	Capacity				Generation				ALL
	Coal	Nat. gas	Hydro	weighted	Coal	Natural gas	Hydro	weighted	Cap&Gen
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Alberta (90-95)	***68.58%***	***21.04%***	***10.37%***		***83.76%***	***12.17%***	***4.08%***		
Arizona	33.80%	19.36%	5.55%	27.83%	33.24%	8.92%	6.54%	29.20%	28.51%
Connecticut	62.84%	20.00%	8.76%	48.21%	75.70%	9.84%	2.65%	64.71%	56.46%
Delaware	25.30%	8.00%	10.34%	20.11%	23.72%	9.43%	4.07%	21.18%	20.65%
Dist of Columbia	68.39%	20.98%	10.34%	52.39%	83.64%	12.15%	4.07%	71.70%	62.05%
Illinois	21.84%	16.20%	10.31%	19.46%	41.17%	11.01%	4.03%	35.99%	27.72%
Maine	68.39%	20.98%	5.43%	51.88%	83.64%	12.15%	23.43%	72.49%	62.19%
Maryland	26.34%	7.86%	6.03%	20.35%	22.08%	9.36%	1.10%	19.67%	20.01%
Massachusetts	50.36%	17.75%	8.28%	39.13%	48.87%	5.62%	1.59%	41.68%	40.41%
Michigan	14.67%	19.06%	8.86%	14.99%	11.20%	11.18%	2.30%	10.84%	12.91%
New Hampshire	45.07%	20.98%	0.72%	35.40%	58.76%	11.66%	4.73%	50.83%	43.11%
New Jersey	56.53%	2.81%	10.34%	40.43%	66.95%	5.35%	4.07%	56.89%	48.66%
New York	56.23%	6.49%	1.29%	40.06%	63.40%	5.63%	19.50%	54.58%	47.32%
Ohio	16.05%	19.33%	9.92%	16.11%	6.42%	11.98%	3.93%	7.00%	11.55%
Oregon	62.82%	18.94%	70.52%	54.39%	76.99%	8.15%	80.82%	68.78%	61.58%
Pennsylvania	16.43%	19.94%	8.55%	16.35%	23.94%	11.68%	2.83%	21.59%	18.97%
Rhode Island	68.39%	30.65%	9.41%	54.33%	83.64%	48.37%	4.07%	76.11%	65.22%

…continued

Table 5.18 (continued)

Restructured Jurisdiction	Capacity				Generation				ALL
	Coal	Nat. gas	Hydro	weighted	Coal	Nat. gas	Hydro	weighted	Cap&Gen
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Texas	37.85%	6.61%	9.41%	28.33%	34.31%	28.26%	3.28%	32.31%	30.32%
Virginia	36.48%	18.16%	5.54%	29.41%	38.32%	9.15%	1.91%	33.29%	31.35%
Arkansas	28.27%	20.35%	1.32%	23.81%	32.29%	6.29%	5.41%	28.03%	25.92%
Montana	18.18%	19.60%	36.54%	20.38%	22.70%	12.01%	34.55%	21.88%	21.13%
Nevada	17.72%	16.96%	8.61%	16.62%	7.29%	4.42%	5.65%	6.88%	11.75%
New Mexico	9.67%	8.33%	9.32%	9.35%	6.48%	5.25%	3.20%	6.19%	7.77%
Oklahoma	30.35%	14.24%	4.98%	24.33%	24.31%	22.26%	2.43%	23.17%	23.75%
California	68.39%	19.35%	10.30%	52.04%	83.64%	28.91%	19.30%	74.36%	63.20%

Note: Column (4) = sum of values in Columns (1)-(3) each weighted by the corresponding Alberta percentages.
Column (8) = sum of values in Columns (5)-(7) each weighted by the corresponding Alberta percentages.
Column (9) = average of values in Columns (4) and (8).

Based on the absolute differences in the last column of Table 5.18, New Mexico (highlighted) is the best match among restructured jurisdictions for Alberta in terms of the composite generation and capacity variable. However, for subsequent use the jurisdictions were ranked from smallest absolute difference to largest (Rhode Island). The composite variables for fuel prices (one for absolute differences, one for correlations) were obtained by averaging the corresponding values for coal and natural gas prices. Again these were done separately for restructured and non-restructured jurisdictions; values for restructured jurisdictions are presented in Table 5.19. As this table shows, Oregon (highlighted) is the best match for Alberta in terms of absolute differences of the fuel price variable, but Virginia (also highlighted) is the best match based on having the highest correlation of fuel prices with Alberta. Again, for subsequent use the jurisdictions were ranked from smallest to largest for absolute differences and from largest to smallest for correlations.

Table 5.19: Absolute Differences and Correlation Computations for Fuel Prices for Restructured Jurisdictions

Restructured Jurisdiction	Natural gas price		Coal price		Fuel price	
	Absolute difference (1)	Correlation (2)	Absolute difference (3)	Correlation (4)	Absolute difference (5)=0.5*[(1)+(3)]	Correlation (6)=0.5*[(2)+(4)]
Arizona	1.08	0.927	0.95	-0.125	1.02	0.401
Connecticut	1.07	0.682	1.98	0.475	1.53	0.578
Delaware	1.30	0.908	1.70	0.293	1.50	0.600
District of Columbia						
Illinois	1.04	0.972	1.05	-0.089	1.04	0.441
Maine						
Maryland	1.34	0.971	1.48	0.605	1.41	0.788
Massachusetts	1.18	0.957	1.77	0.098	1.47	0.527
Michigan	0.58	0.892	1.06	0.136	0.82	0.514
New Hampshire	0.67	0.814	1.70	0.598	1.18	0.706
New Jersey	1.10	0.955	1.91	0.402	1.51	0.678
New York	1.25	0.982	1.46	0.537	1.36	0.759
Ohio	1.74	0.708	1.20	0.049	1.47	0.379
Oregon	0.36	0.909	0.59	0.010	0.48	0.460
Pennsylvania	1.66	0.652	1.23	0.125	1.44	0.389
Rhode Island	1.33	0.976				

…continued

Table 5.19 (continued)

Restructured Jurisdiction	Natural gas price		Coal price		Fuel price	
	Absolute difference (1)	Correlation (2)	Absolute difference (3)	Correlation (4)	Absolute difference (5)=0.5*[(1)+(3)]	Correlation (6)=0.5*[(2)+(4)]
Texas	0.94	0.968	0.61	0.673	0.78	0.820
Virginia	1.36	0.961	1.42	0.682	1.39	0.822
Arkansas	0.69	0.885	0.83	0.011	0.76	0.448
Montana	1.64	0.632	0.22	-0.357	0.93	0.138
Nevada	1.15	0.765	1.09	0.318	1.12	0.542
New Mexico	0.69	0.881	0.86	0.183	0.77	0.532
Oklahoma	1.35	0.894	0.52	0.320	0.94	0.607
California	1.72	0.665	0.31		1.01	

For electricity demand, with no obvious way to weight HDD, real GDP, and growth in real GDP, it was decided to rely on absolute differences obtained for the real growth rate variable since this is expected to be the key variable in terms of reflecting changes in electricity demand. Restructured and non-restructured jurisdictions were ranked from smallest to largest absolute difference between their average real GDP growth and the corresponding value for Alberta.

While the amalgamation of variables described above results in some loss of information, since matching of jurisdictions is based on only three composite variables, such a reduction is necessary for feasibility purposes. However, even based on the three composite variables, a unique restructured and non-restructured jurisdiction that best matched Alberta could not be determined, as is evident from Table 5.20.

Table 5.20: Jurisdiction Correspondences for Alberta based on the Three Composite Variables

Matching Jurisdiction	Generation and capacity	Electricity Demand	Fuel Prices	
	Absolute differences	Absolute differences	Absolute differences	correlation
Restructured	New Mexico	Illinois	Oregon	Virginia
Non-restructured	Missouri	Wisconsin	Kansas	Kentucky

To resolve this issue, the rankings of the absolute differences and the fuel price correlations between Alberta and each of the restructured and non-restructured US jurisdictions were examined more closely. Specifically, for each of the composite variables, the rank of each jurisdiction based on the absolute differences sorted in ascending order and the fuel price correlations sorted in descending order were obtained. Based on this procedure, the jurisdictions with the lowest sums of rankings were determined, as summarized in Table 5.21.

Table 5.21: Matching Jurisdictions based on Composite Variable Rankings

Composite Variable	Restructured Jurisdiction				Non-restructured Jurisdiction			
	Texas	Maryland	Oklahoma	Illinois	Kansas	Missouri	N. Carolina	Minnesota
Generation and Capacity	13	6	9	11	8	1	12	7
Electricity Demand	3	7	9	1	4	10	7	5
Fuel Prices	4	15	7	10	1	12	2	6
Fuel Prices correlation	2	3	7	16	10	4	7	16
Sum of rankings	**22**	**31**	**32**	**38**	**23**	**27**	**28**	**34**

Based on the lowest totals in the last line of Table 5.21, Texas and Kansas are selected as the restructured and non-restructured jurisdictions, respectively, that best match Alberta. Data from these best matching jurisdictions will be used to determine the impact of restructuring on the endogenous variables in the post restructuring period, as described in Section 5.9. Information from the next best ranking jurisdictions is used to test the sensitivity of the results to these choices, as described in Section 5.10.2.

5.8 Determining a Jurisdiction that Did Not Restructure its Electricity Market that Closely Mimics a Jurisdiction that Restructured its Electricity Market

An alternative to adjusting values of the endogenous variables in Alberta in the post-restructuring period using information based on comparisons of Alberta with restructured and non-restructured US jurisdictions is to use information based just on comparisons between restructured and non-restructured US jurisdictions. Specifically, if two otherwise similar US jurisdictions can be found, where one restructured and the other did not, then differences between the values of the endogenous variables in these two jurisdictions in the post-restructuring period can provide information about the likely effects that restructuring had on the values of these endogenous variables in Alberta, and hence can be used to make adjustments to the observed values of these variables in Alberta in this period.

Of course, as with the comparisons of Alberta and US jurisdictions in order to determine similarities, it is unlikely that any single non-restructured jurisdiction will perfectly match a restructured jurisdiction on the basis of all the endogenous and exogenous variables. Thus, it will be necessary, as with the Alberta-US jurisdiction comparisons to determine the best matches according to a number of aggregate criteria.

To begin, each of the 24 US jurisdictions that restructured its electricity market is compared with each of the 27 jurisdictions that did not restructure their electricity market on the basis of the available data set from the Energy Information Administration *EIA* website of the Department of Energy of the US. The variables have already been described in Section 5.4. The objective is to compare the values of both the endogenous variables for the pre restructuring period and the exogenous variables for the entire 1990 – 2004 period for each of the 24 restructured jurisdictions with the same variables for each of the 27 non-restructured jurisdictions. As before, the endogenous variables reflect a variety of variables pertaining to each fuel, including capacity (percentage share of each fuel in the total), generation (percentage share of each fuel in the total), fuel consumption (percentage share of coal and of natural gas), utilization ratios (for coal and natural gas), and heat rates (for coal and natural gas). In addition, there are also two interaction variables between fuel prices (for coal and natural gas) and the share of the respective fuel-based generation. The six exogenous variables reflect fuel prices (coal prices, natural gas prices), electricity demand (real GDP, real GDP growth, HDD) and operating costs (annual wage / worker).

Both absolute differences and correlations (based on the 19 endogenous variables for the pre-restructuring period and the 6 exogenous variables for the 1990 – 2004 period) for each of the restructured jurisdictions with each of the 27 non-restructured jurisdictions were computed. The absolute differences were also averaged to obtain a single number for comparison purposes. The correlations and absolute differences for the 19 endogenous variables were computed for the pre-restructuring period as the objective is to determine the similarity of the two jurisdictions in the pre-restructuring period. Since the exogenous variables are assumed not to be affected by restructuring, and since in most cases there are relatively few observations in the pre-restructuring period, they are examined over the entire period that is available. Here, the range of the pre-restructuring period is defined by the availability of data, which goes back to 1990 and ends one year prior to the year of restructuring.

For illustration purposes, Table 5.22 shows these computations for the restructured jurisdiction of Arizona for the coal (share of) capacity variable. In this table the correlations for Hawaii, Idaho and Vermont are missing because the coal (share of) capacity figures were 0% for all three of these states.

Table 5.22: Sample Computation of Correlation and Absolute Differences for the Pre–Restructuring Period 1990 – 1997; Coal Share of Capacity Figures for Arizona

Arizona	Alaska	Alabama	Colorado	Florida	Georgia	Hawaii	Iowa	Idaho	Indiana
Correlation 1990-1997	0.6203	0.2513	0.2780	0.6034	0.6740		0.1485		0.5068
Absolute Differences (percentage points):									
1990	31.44	24.86	41.13	4.52	26.46	34.52	37.82	34.52	60.00
1991	31.79	24.22	40.84	4.85	28.64	34.87	36.61	34.87	58.95
1992	31.74	24.46	40.77	5.23	28.07	34.62	36.80	34.62	58.87
1993	31.76	24.32	40.68	6.83	28.27	34.58	36.08	34.58	58.49
1994	31.68	24.42	40.55	6.60	27.11	34.46	36.43	34.46	57.69
1995	31.65	23.34	40.85	6.63	24.83	34.45	36.68	34.45	55.95
1996	31.76	22.14	39.05	5.53	25.42	34.56	35.21	34.56	57.14
1997	31.77	20.83	38.90	5.32	24.57	34.54	31.20	34.54	56.04
average	31.70	23.57	40.34	5.69	26.67	34.58	35.85	34.58	57.89

Arizona	Kansas	Kentucky	Louisiana	Minnesota	Missouri	Mississippi	N. Carolina	N. Dakota
Correlation 1990-1997	-0.3336	0.4006	0.3733	0.5322	0.4342	0.5421	0.2106	-0.5132
Absolute Differences (percentage points):								
1990	18.86	58.40	14.78	28.27	35.05	4.14	25.61	51.94
1991	18.48	57.94	15.18	28.10	34.77	4.55	25.22	51.61
1992	18.65	58.18	14.78	28.34	34.42	4.75	25.47	52.37
1993	18.70	58.23	14.96	27.82	34.31	4.71	25.51	52.44
1994	19.03	57.08	14.83	27.61	34.43	4.91	26.55	52.56
1995	19.33	57.24	17.91	26.55	31.99	4.90	23.51	52.57
1996	19.16	55.69	15.12	26.29	31.13	5.04	22.38	52.59
1997	19.83	56.26	14.37	26.35	32.54	5.41	22.15	52.27
average	19.00	57.38	15.24	27.42	33.58	4.80	24.55	52.30

…continued

Table 5.22 (continued)

Arizona	Nebraska	S. Carolina	S. Dakota	Tennessee	Utah	Vermont	Washington	Wisconsin
Correlation 1990-1997	0.1296	-0.6797	0.5640	0.0853	0.3439		0.5935	0.5485
Absolute Differences (percentage points):								
1990	21.68	1.90	15.52	20.50	55.59	34.52	28.28	32.85
1991	20.31	4.46	16.06	20.14	54.55	34.87	28.48	32.19
1992	20.35	4.21	15.93	20.35	54.42	34.62	28.24	32.36
1993	20.25	3.89	17.32	20.40	54.21	34.58	28.20	30.69
1994	20.37	1.54	17.72	21.02	53.96	34.46	28.14	28.07
1995	20.38	1.61	17.69	20.47	53.92	34.45	28.34	26.10
1996	19.30	2.05	18.41	16.74	53.88	34.56	28.23	25.58
1997	21.68	0.47	17.73	16.76	52.54	34.54	28.40	25.65
average	20.31	2.52	17.05	19.55	54.13	34.58	28.29	29.19

Arizona	W. Virginia	Wyoming
Correlation 1990-1997	-0.35128	0.601361
Absolute Differences (percentage points):		
1990	64.68	60.93
1991	64.33	60.58
1992	64.58	60.50
1993	64.63	60.55
1994	64.75	60.59
1995	65.05	60.63
1996	64.91	60.58
1997	64.67	60.69
average	64.70	60.63

Once the correlation and average absolute differences (for the pre-restructuring period for the endogenous variables and the entire 1990 – 2004 period for the exogenous variables) are computed for each of the 24 restructured jurisdictions, for each variable in each restructured jurisdiction the correlations are sorted in descending order and the absolute differences are sorted in ascending order to determine the non-restructured jurisdiction that best matches the particular restructured jurisdiction. This sorting is illustrated for Arizona for the coal share of capacity variable in Table 5.23.

Table 5.23: Sample Sorting of Correlation and Absolute Differences for the Pre–Restructuring Period 1990 – 1997 – Coal Capacity Share for Arizona

Jurisdiction	Correlation (descending order)	Jurisdiction	Absolute differences (ascending order)
Georgia	0.6740	South Carolina	2.52
Alaska	0.6203	Mississippi	4.80
Florida	0.6034	Florida	5.69
Wyoming	0.6014	Louisiana	15.24
Washington	0.5935	South Dakota	17.05
South Dakota	0.5640	Kansas	19.00
Wisconsin	0.5485	Tennessee	19.55
Mississippi	0.5421	Nebraska	20.13
Minnesota	0.5322	Alabama	23.57
Indiana	0.5068	North Carolina	24.55
Missouri	0.4342	Georgia	26.67
Kentucky	0.4006	Minnesota	27.42
Louisiana	0.3733	Washington	28.29
Utah	0.3439	Wisconsin	29.19
Colorado	0.2780	Alaska	31.70
Alabama	0.2513	Missouri	33.58
North Carolina	0.2106	Hawaii	34.58
Iowa	0.1485	Idaho	34.58
Nebraska	0.1296	Vermont	34.58
Tennessee	0.0853	Iowa	35.85
Kansas	-0.3336	Colorado	40.34
West Virginia	-0.3513	North Dakota	52.30
North Dakota	-0.5132	Utah	54.13
South Carolina	-0.6797	Kentucky	57.38
Hawaii		Indiana	57.89
Idaho		Wyoming	60.63
Vermont		West Virginia	64.70

As noted earlier, correlations of the Arizona coal share of capacity with the coal shares of capacity for Hawaii, Idaho and Vermont are not available because the coal shares of capacity figures for these non-restructured states are 0% for the entire time period 1990 – 1997. Similarly, for some other jurisdictions and variables, correlations and absolute differences cannot be computed because the data for those variables are not available. For instance, for Hawaii, since total fuel consumption is reported as zero GJ, the data on coal and natural gas consumption and by extension the coal and natural gas based heat rates are unavailable, therefore the correlation and absolute differences of the restructured jurisdictions for these variables with respect to Hawaii cannot be computed.

Typically, selection of the non-restructured jurisdiction that best mimics the restructured jurisdiction in question based on the correlation criterion will provide a different outcome than if the selection is based the absolute difference criterion. For instance in Table 5.23, based on correlations the best match to Arizona in terms of the coal share of capacity is Georgia, whereas based on absolute differences the best match would be South Carolina. When conflicts of this type arise, the final selection is based on the absolute difference criterion because while the correlation captures the trend or movement in the variables, absolute differences provide a better picture of proximity of the two jurisdictions with respect to a particular variable. In addition, as will be seen later, the approach based on absolute differences is consistent with the difference-in-differences procedure used in Section 5.9 to determine the adjustments to be made to the values of the endogenous variables in the post-restructuring period.

One exception to using absolute differences as the comparison criterion is in the case of fuel prices, as in that case, the proximity in the trend in coal and natural gas prices (reflected in the correlations) is potentially as useful as the proximity in the values of coal and natural gas prices (reflected in the absolute differences). Part of the reason is that fuel prices change much more frequently and typically by smaller magnitudes than variables such as capacity additions, which tend to change only periodically and often by large amounts.

Of course, while South Carolina is the most similar to Arizona in terms of (absolute differences in) coal share of capacity, as shown in Table 5.23, this may not be the case for comparisons based on other variables. These comparisons, summarized for all the restructured jurisdictions in Table 5.24, indicates that South Carolina is not the best match for Arizona for any other variable, and that 15 different non-restructured jurisdictions match Arizona the best based on the different variable comparisons.

Table 5.24: Jurisdiction to Jurisdiction Correspondence based on Absolute Difference Computations

Restructured Jurisdiction	Coal based capacity	Hydro based capacity	Gas based capacity	Nuclear based capacity	Total capacity	Coal based generation	Hydro based generation	Gas based generation
Arizona	S. Carolina	Alaska	Kentucky	N. Carolina	Missouri	Florida	Alabama	Utah
Connecticut	Washington	Minnesota	Idaho	Vermont	Mississippi	Alaska	Wyoming	Minnesota
Delaware	Kansas	Louisiana	Louisiana	Alaska	Idaho	N. Carolina	Louisiana	Florida
Dist of Columbia	Hawaii	Louisiana	Tennessee	Alaska	Vermont	Hawaii	Louisiana	Hawaii
Illinois	Kansas	Kansas	S. Dakota	S. Carolina	Florida	Florida	Kansas	Minnesota
Maine	Hawaii	Alabama	Tennessee	S. Carolina	Idaho	Hawaii	Alaska	Hawaii
Maryland	S. Carolina	Kentucky	Louisiana	Georgia	Wisconsin	N. Carolina	Kentucky	Utah
Massachusetts	S. Dakota	Minnesota	Idaho	Missouri	Minnesota	S. Carolina	Utah	Florida
Michigan	Kansas	Iowa	Missouri	Minnesota	Washington	Wisconsin	Minnesota	Missouri
New Hampshire	Louisiana	Georgia	Hawaii	Vermont	S. Dakota	Louisiana	N. Carolina	Wisconsin
New Jersey	S. Dakota	Louisiana	Louisiana	N. Carolina	W. Virginia	Washington	Louisiana	Florida
New York	S. Dakota	N. Dakota	Louisiana	Georgia	Florida	Washington	Alaska	Florida
Ohio	N. Dakota	Indiana	Iowa	Missouri	Washington	N. Dakota	Florida	Tennessee
Oregon	Washington	Washington	Missouri	Alaska	Kansas	Alaska	Washington	Kansas
Pennsylvania	Kansas	Minnesota	Wisconsin	N. Carolina	Florida	N. Carolina	Wyoming	Wisconsin
Rhode Island	Hawaii	W. Virginia	Alabama	Alaska	Vermont	Hawaii	Louisiana	Alaska
Texas	Mississippi	W. Virginia	Louisiana	Missouri	Florida	Florida	W. Virginia	Louisiana
Virginia	S. Carolina	Wyoming	Missouri	Alabama	W. Virginia	Florida	Minnesota	Utah
Arkansas	S. Carolina	Tennessee	S. Carolina	Mississippi	Minnesota	Nebraska	Alabama	Kansas
Montana	Kansas	S. Dakota	Kentucky	Alaska	Utah	N. Carolina	Alaska	Tennessee
Nevada	Kansas	Alaska	S. Dakota	Alaska	Nebraska	Kansas	Alabama	Florida
New Mexico	Colorado	Iowa	Louisiana	Alaska	Nebraska	N. Dakota	W. Virginia	Kansas
Oklahoma	S. Carolina	Utah	Mississippi	Alaska	W. Virginia	Nebraska	Nebraska	Louisiana
California	Hawaii	Alaska	Alaska	Florida	Florida	Hawaii	Alaska	Louisiana

…continued

Table 5.24 (continued):

Restructured Jurisdiction	Nuclear based generation	Total generation	Coal consumption	Total consumption	Coal based heat rate	Gas based heat rate	Coal based utilization	Gas based utilization
Arizona	Mississippi	S. Carolina	Kansas	Minnesota	Indiana	Indiana	Florida	Alabama
Connecticut	S. Carolina	N. Dakota	Florida	Alaska	S. Carolina	Louisiana	Florida	Minnesota
Delaware	Alaska	Hawaii	Florida	S. Dakota	Kentucky	Florida	Georgia	Mississippi
Dist of Columbia	Alaska	Alaska		Hawaii				
Illinois	S. Carolina	Florida	Utah	Kentucky	Colorado	Kansas	Iowa	Kansas
Maine	S. Carolina	Hawaii		Hawaii				
Maryland	Georgia	Wyoming	Kansas	S. Carolina	N. Carolina	Colorado	W. Virginia	Nebraska
Massachusetts	Missouri	N. Dakota	Florida	Washington	N. Carolina	Louisiana	Colorado	Mississippi
Michigan	Louisiana	Kentucky	Washington	West Virginia	Indiana	Iowa	Indiana	Alabama
New Hampshire	S. Carolina	Idaho	Washington	Alaska	W. Virginia	W. Virginia	S. Dakota	Tennessee
New Jersey	S. Carolina	Utah	Mississippi	Washington	Florida	Alaska	Iowa	Indiana
New York	Wisconsin	Indiana	Louisiana	Wisconsin	Florida	Louisiana	Alaska	Florida
Ohio	Iowa	Florida	Tennessee	Indiana	Alabama	Wisconsin	Indiana	Iowa
Oregon	Alaska	Minnesota	Florida	S. Dakota	Wyoming	Florida	Washington	Utah
Pennsylvania	Mississippi	Florida	Wisconsin	Florida	Florida	Alaska	W. Virginia	Washington
Rhode Island	Alaska	Alaska	Vermont	Vermont		Colorado		S. Carolina
Texas	Iowa	Florida	Florida	Indiana	Louisiana	Louisiana	Colorado	Louisiana
Virginia	Mississippi	Wisconsin	Kansas	S. Carolina	N. Carolina	W. Virginia	Kentucky	Minnesota
Arkansas	Georgia	Wyoming	Kansas	Utah	Wyoming	Alaska	W. Virginia	Minnesota
Montana	Alaska	Nebraska	Tennessee	S. Carolina	Kansas	Kentucky	Colorado	Nebraska
Nevada	Alaska	Nebraska	Kansas	Nebraska	Indiana	Louisiana	Florida	Mississippi
New Mexico	Alaska	N. Dakota	Kansas	Colorado	Wisconsin	Louisiana	Colorado	Louisiana
Oklahoma	Alaska	Wisconsin	Florida	Wyoming	Wyoming	Wyoming	Tennessee	Louisiana
California	Minnesota	Florida	Vermont	Wyoming		Wyoming		Louisiana

…continued

Table 5.24 (continued):

Restructured Jurisdiction	Real GDP	Heating Degree Days	Natural gas price	Coal price	Annual wage / worker	Real GDP growth	Sgas = Share of gas based generation × gas price	Scoal = Share of coal based generation × coal price
Arizona	Colorado	Louisiana	Alabama	Indiana	Minnesota	Georgia	Kansas	Minnesota
Connecticut	Wisconsin	Indiana	Florida	Florida	Hawaii	Kansas	S. Dakota	S. Dakota
Delaware	W. Virginia	Kentucky	Wisconsin	Florida	Hawaii	Missouri	Mississippi	Georgia
Dist of Columbia	Mississippi				Hawaii	Hawaii		
Illinois	Florida	Nebraska	Mississippi	W. Virginia	Hawaii	Kansas	Minnesota	Iowa
Maine	Idaho	Vermont	Florida		Idaho	Kansas		
Maryland	Minnesota	Kentucky	Florida	S. Carolina	Minnesota	Vermont	Utah	Utah
Massachusetts	N. Carolina	Nebraska	Wisconsin	Florida	Hawaii	Vermont	Florida	Wyoming
Michigan	Georgia	Utah	Alaska	Tennessee	Minnesota	S. Carolina	N. Carolina	Kentucky
New Hampshire	W. Virginia	Wisconsin	Mississippi	Florida	Hawaii	Minnesota	Wisconsin	N. Dakota
New Jersey	Georgia	W. Virginia	Florida	Florida	Hawaii	Kansas	Florida	N. Dakota
New York	Florida	Indiana	Florida	S. Carolina	Hawaii	Vermont	Mississippi	Louisiana
Ohio	Florida	Indiana	Indiana	W. Virginia	N. Dakota	Missouri	Tennessee	West Virginia
Oregon	S. Carolina	Kansas	Kansas	Minnesota	Colorado	Utah	Colorado	Washington
Pennsylvania	Florida	Indiana	S. Dakota	W. Virginia	Minnesota	Kansas	Wisconsin	Florida
Rhode Island	Idaho	Indiana	Vermont		Georgia	Vermont	Louisiana	
Texas	Florida	Louisiana	Mississippi	Minnesota	Minnesota	Florida	Louisiana	N. Dakota
Virginia	N. Carolina	Kentucky	Indiana	S. Carolina	Alabama	Florida	Kansas	Wisconsin
Arkansas	Mississippi	N. Carolina	Missouri	Louisiana	Louisiana	Tennessee	Kansas	Wyoming
Montana	S. Dakota	Wyoming	Alabama	Nebraska	Louisiana	Alabama	Tennessee	Nebraska
Nevada	Utah	N. Carolina	Minnesota	Tennessee	Alabama	Utah	Florida	Utah
New Mexico	W. Virginia	Kentucky	Kansas	Washington	Louisiana	Tennessee	Kansas	Colorado
Oklahoma	Iowa	N. Carolina	N. Carolina	Kansas	Louisiana	Kansas	Louisiana	Minnesota
California	Florida	Mississippi	S. Dakota	N. Dakota	Minnesota	Vermont	Louisiana	Washington

As is evident from Table 5.24, correspondences based on some variables could not be determined for all jurisdictions, especially for jurisdictions like District of Columbia and Maine, because values for some variables were not available for those jurisdictions. However, these are exceptions and do not hamper the remainder of the analysis.

One way to determine the non-restructured jurisdiction that best mimics, for example, Arizona, would be to choose the jurisdiction that best mimics Arizona on the greatest number of variables. In this case there would be three contenders – Alabama (based on the hydro-based share of generation, natural gas-based utilization, and natural gas prices), Indiana (based on the natural gas-based heat rate, the coal-based heat rate and the coal price) and Minnesota (based on total fuel consumption, annual wage/worker and the share of coal-based generation), as each of these jurisdictions has the lowest average absolute difference for three variables.

An important issue in using this approach is that one or more other criteria will subsequently have to be considered to select one jurisdiction from among these three, and more importantly, merely selecting jurisdictions on the basis on the quantity or number of best matching variables ignores the quality and importance of those variables. An alternative approach would be to reduce the number of variables in the comparative framework used to determine the jurisdictional correspondence by combining or ignoring certain variables based on their relative importance. For instance, the absolute difference calculations for the four capacity share variables and the four generation share variables – the shares of coal-based, natural gas-based, hydro-based and nuclear-based capacity and generation – can all be combined by using weights from Alberta.

Specifically, average percentage capacity share figures for Alberta for the pre-restructuring period 1990–1995 were used to weight the correlation and absolute difference computations for the capacity share data for all the 24 restructured jurisdictions. Similarly, the average percentage generation figures for Alberta for the pre-restructuring period 1990–1995 were used to weight the correlation and absolute difference computations for the generation share data for all the 24 restructured jurisdictions. These four sets of absolute differences for capacity and generation shares will provide us with combined capacity calculation figures and combined generation calculation figures, which can then be (equally) weighted to form an overall value. With this calculation, information on total capacity and total generation are not used. In addition, coal and natural gas consumption data are also ignored as some of this information will be captured through fuel prices, considered subsequently. Likewise, secondary variables like utilization, heat rates and the two interaction variables are not considered explicitly as the basic information they provide will already be reflected in the generation and capacity figure calculations.

Table 5.25 indicates these weighting computations for the capacity and generation share data for Arizona for the period 1990-1997. Based on the weighted capacity share variables, South Carolina (highlighted) is the best match for Arizona, whereas Florida (also highlighted) is the best match for Arizona based on the weighted generation variables. Overall, based on the average of these two weighted variables, the best match for Arizona is Florida (also highlighted).

Table 5.25: Weighting the Absolute Difference Computations for Arizona (1990-1997)

Non-restructured jurisdiction	Capacity Shares				
	coal	hydro	gas	others	weighted
	(1)	(2)	(3)	(4)	(5)
Alberta (90-95)	***68.39%***	***10.34%***	***20.98%***	***0.29%***	
Alaska	31.70	2.35	31.03	25.35	28.51
Alabama	23.57	2.72	1.21	1.14	16.66
Colorado	40.34	7.58	1.29	25.35	28.72
Florida	5.69	15.87	4.11	14.66	6.44
Georgia	26.67	7.18	1.29	8.41	19.28
Hawaii	34.58	15.79	1.29	25.35	25.62
Iowa	35.85	14.48	0.43	18.59	26.16
Idaho	34.58	79.36	3.87	25.35	32.74
Indiana	57.89	15.59	0.76	25.35	41.43
Kansas	19.00	15.98	3.75	13.68	15.48
Kentucky	57.38	11.69	0.31	25.35	40.59
Louisiana	15.24	15.98	11.57	13.09	14.54
Minnesota	27.42	14.46	1.04	6.55	20.48
Missouri	33.58	13.09	1.16	18.06	24.61
Mississippi	4.80	15.98	6.37	6.42	6.29
N. Carolina	24.55	7.95	0.95	1.12	17.81
N. Dakota	52.30	4.90	1.23	25.35	36.60
Nebraska	20.13	12.84	1.20	2.37	15.35
S. Carolina	2.52	8.99	1.14	13.05	2.93
S. Dakota	17.05	44.29	4.84	25.35	17.33
Tennessee	19.55	4.27	1.41	10.49	14.14
Utah	54.13	10.92	2.51	25.35	38.75
Vermont	34.58	16.70	1.41	24.49	25.74
Washington	28.29	67.76	1.34	20.31	26.69
Wisconsin	29.19	12.01	0.57	11.46	21.36
W. Virginia	64.70	15.38	1.41	25.35	46.21
Wyoming	60.63	11.41	1.41	25.35	43.01

Note: Column (5) = sum of values in Columns (1)-(4) each weighted by the corresponding Alberta percentages.
For Arizona, "Other" refers to nuclear.

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Table 5.25 (continued)

Non-restructured jurisdiction	Generation Shares					ALL
	coal	hydro	gas	others	weighted	Cap & Gen
	(6)	(7)	(8)	(9)	(10)	(11)
Alberta (90-95)	***83.64%***	***4.07%***	***12.15%***	***0.14%***		
Alaska	42.42	13.06	55.65	36.19	42.82	35.66
Alabama	18.48	2.40	2.52	15.07	15.88	16.27
Colorado	44.92	6.47	1.89	36.19	38.11	33.41
Florida	4.43	11.34	14.07	18.44	5.90	6.17
Georgia	16.80	6.96	2.79	7.12	14.68	16.98
Hawaii	48.71	11.25	3.05	36.19	41.62	33.62
Iowa	35.76	8.66	2.31	24.49	30.57	28.37
Idaho	48.71	88.49	3.05	36.19	44.76	38.75
Indiana	49.86	11.05	2.43	36.19	42.50	41.97
Kansas	22.69	11.50	2.77	13.46	19.80	17.64
Kentucky	46.81	7.25	2.98	36.19	39.86	40.22
Louisiana	16.13	11.51	40.25	12.94	18.87	16.71
Minnesota	16.52	9.61	1.97	6.88	14.45	17.47
Missouri	32.61	8.46	2.21	21.84	27.92	26.27
Mississippi	10.53	11.51	19.06	3.97	11.60	8.94
N. Carolina	12.57	5.84	2.81	4.56	11.10	14.46
N. Dakota	43.63	4.01	3.05	36.19	37.08	36.84
Nebraska	11.86	6.21	2.10	4.17	10.44	12.90
S. Carolina	13.45	7.34	2.52	24.50	11.89	7.41
S. Dakota	13.03	52.32	2.70	36.19	13.41	15.37
Tennessee	19.59	3.02	2.95	16.93	16.89	15.51
Utah	46.78	9.04	1.64	36.19	39.75	39.25
Vermont	48.71	7.38	2.40	42.03	41.39	33.57
Washington	40.19	72.91	2.73	29.83	36.95	31.82
Wisconsin	24.27	7.13	2.20	15.12	20.88	21.12
W. Virginia	50.46	10.99	3.02	36.19	43.07	44.64
Wyoming	48.93	9.32	3.03	36.19	41.73	42.37

Note: Column (10) = sum of values in Columns (6)-(9) each weighted by the corresponding Alberta percentages.
Column (11) = average of values in Columns (5) and (10).
For Arizona, "Other" refers to nuclear.

The absolute difference computations considered to this point are for the endogenous variables, although as discussed subsequently, not all of these are used explicitly to determine jurisdictional correspondences. As far as the 6 exogenous variables are concerned, the computations for coal and gas prices were combined to obtain a single set of absolute differences. Table 5.26 shows a sample computation for Arizona fuel prices.

Table 5.26: Absolute Differences and Correlation Computations for Fuel Prices in Arizona, 1990-2004

Non-restructured jurisdiction	Natural Gas price		Coal price		Fuel price	
	Correlation (1)	Absolute difference (2)	Correlation (3)	Absolute difference (4)	Correlation (5) =0.5*[(1)+(3)]	Absolute difference (6) =0.5*[(2)+(4)]
Alabama	0.9725	0.24	0.8019	0.41	0.8872	0.3231
Alaska	0.7962	1.63				
Colorado	0.9410	0.37	0.8091	0.35	0.8751	0.3601
Florida	0.9567	0.32	0.4582	0.70	0.7075	0.5102
Georgia	0.7758	0.60	0.2990	0.54	0.5374	0.5703
Hawaii						
Idaho						
Indiana	0.9636	0.33	0.6208	0.09	0.7922	0.2123
Iowa	0.9579	0.55	0.7743	0.51	0.8661	0.5282
Kansas	0.9712	0.43	0.5714	0.42	0.7713	0.4263
Kentucky	0.9521	0.52	-0.1531	0.12	0.3995	0.3161
Louisiana	0.9715	0.32	0.9299	0.18	0.9507	0.2501
Minnesota	0.9501	0.33	0.6702	0.35	0.8101	0.3404
Mississippi	0.9192	0.40	0.0022	0.44	0.4607	0.4194
Missouri	0.9753	0.30	0.6272	0.36	0.8012	0.3322
Nebraska	0.9549	0.30	0.7073	0.74	0.8311	0.5200
N. Carolina	0.9261	0.48	-0.0234	0.61	0.4514	0.5452
N. Dakota	0.8675	1.69	-0.3182	0.82	0.2746	1.2524
S. Carolina	0.6501	0.80	0.0078	0.55	0.3290	0.6771
S. Dakota	0.4271	0.41	-0.6914	0.49	-0.1322	0.4533
Tennessee	-0.1417	0.64	0.3959	0.09	0.1271	0.3695
Utah	0.6298	0.68	0.5929	0.10	0.6113	0.3894
Vermont	0.9337	0.26				
Washington	0.0545	7.36	-0.2922	0.19	-0.1189	3.7722
W. Virginia	0.7723	1.12	0.5337	0.23	0.6530	0.6791
Wisconsin	0.9609	0.30	0.6295	0.28	0.7952	0.2873
Wyoming	-0.2982	2.75	0.2454	0.61	-0.0264	1.6792

As Table 5.26 shows (with best matches highlighted), based on the weighted fuel prices, Louisiana is the best match for Arizona in terms of correlations, whereas Indiana is the best match in terms of absolute differences. Fuel price computations are not available for states like Alaska, Hawaii, Idaho and Vermont as either one or both coal and natural gas prices were not available for these states. Nonetheless, these fuel price computations were obtained for all 24 restructured jurisdictions.

In terms of the other exogenous variables, annual wage / worker is ignored for the jurisdictional correspondence analysis as it is relatively unimportant compared to variables that capture fuel prices and electricity demand. As far as electricity demand is concerned, we focus on real GDP growth rather than real GDP, as the former is likely to reflect growth in electricity demand in contrast to the actual level of GDP that likely reflects a number of factors that may have little to do with electricity demand. Absolute difference computations based on real GDP growth are considered in conjunction with HDD-based computations to determine a single set of jurisdiction correspondences that would indicate proximity in electricity demand between the two types of jurisdictions.[32] Since there seems to be no obvious way to combine these two measures, jurisdictional correspondence is based on real GDP growth rather than HDD, as small changes in growth are expected to be of greater importance in affecting electricity demand than even a 200 – 300 unit change in HDD values.

To summarize, in determining which non-restructured jurisdiction is most similar to each restructured jurisdiction, information on the 19 endogenous variables was reduced to a computation based on one composite variable that captured both generation and capacity for the pre-restructuring period. In addition, information on the six exogenous variables was reduced to two composite variables that capture fuel prices and electricity demand. Thus, rather than using computations of absolute differences and correlations for 25 variables, calculations for only three composite variables will be considered in order to determine jurisdictional correspondences.

Table 5.27 shows the jurisdiction correspondences based on correlations and on absolute differences for fuel prices, and based on absolute differences for electricity demand and for the capacity and generation composite variable. Columns (5) and (6) indicate that for the fuel price variable, different jurisdictional correspondences are found alternately using the correlation and absolute differences criteria. In terms of selecting between the correlation and absolute difference criteria, to be consistent with the other composite variables, smallest absolute differences are also used for determining the most similar jurisdiction using the fuel price composite variable.

The final jurisdiction correspondences are shown in columns (7) – (9) of Table 5.27, based on best matches using the three composite variables. Data from these best matching jurisdictions will be used to determine the impact of restructuring on the endogenous variables in the post restructuring period, as described in Section 5.9.

[32] As noted earlier, CDDs are ignored.

Table 5.27: Jurisdiction Correspondences based on Fuel Prices, Electricity Demand and the Capacity Composite Variable

Restructured jurisdiction	Natural Gas price		Coal price	
	Correlation (1)	Absolute Difference (2)	Correlation (3)	Absolute Difference (4)
Arizona	Missouri	Alabama	Louisiana	Indiana
Connecticut	Nebraska	Florida	Kansas	Florida
Delaware	Kansas	Wisconsin	Mississippi	Florida
Dist of Columbia				
Illinois	Kansas	Mississippi	Louisiana	W. Virginia
Maine		Florida		
Maryland	Mississippi	Florida	Alabama	S. Carolina
Massachusetts	Kansas	Wisconsin	S. Dakota	Florida
Michigan	Minnesota	Alaska	Alabama	Tennessee
New Hampshire	S. Carolina	Mississippi	S. Carolina	Florida
New Jersey	Mississippi	Florida	S. Carolina	Florida
New York	Kansas	Florida	Mississippi	S. Carolina
Ohio	Minnesota	Indiana	Minnesota	W. Virginia
Oregon	N. Dakota	Kansas	S. Dakota	Minnesota
Pennsylvania	N. Dakota	S. Dakota	Alabama	W. Virginia
Rhode Island	Kansas	Vermont		
Texas	Kansas	Mississippi	N. Carolina	Minnesota
Virginia	Louisiana	Indiana	S. Carolina	S. Carolina
Arkansas	Missouri	Missouri	Louisiana	Louisiana
Montana	N. Dakota	Alabama	Utah	Nebraska
Nevada	Minnesota	Minnesota	Indiana	Tennessee
New Mexico	Iowa	Kansas	S. Dakota	Washington
Oklahoma	N. Carolina	N. Carolina	Missouri	Kansas
California	Minnesota	S. Dakota		N. Dakota

Table 5.27 (continued)

Restructured jurisdiction	Fuel price		Capacity & generation	Real GDP growth	Fuel price
	Correlation (5)	Absolute Difference (6)	(7)	(8)	(9)
Arizona	Louisiana	Indiana	Florida	Georgia	Indiana
Connecticut	Kansas	Florida	Hawaii	Missouri	Florida
Delaware	Mississippi	Florida	Nebraska	Missouri	Florida
Dist of Columbia			Hawaii	Hawaii	
Illinois	Louisiana	Louisiana	Florida	Indiana	Louisiana
Maine			Vermont	Wisconsin	
Maryland	Alabama	Alabama	Nebraska	Kansas	Alabama
Massachusetts	Mississippi	Florida	Louisiana	Kansas	Florida
Michigan	S. Dakota	Tennessee	Kansas	Indiana	Tennessee
New Hampshire	S. Carolina	Florida	S. Carolina	Vermont	S. Carolina
New Jersey	S. Carolina	Florida	Louisiana	Kansas	Florida
New York	Mississippi	Florida	Louisiana	Kansas	Florida
Ohio	Minnesota	Alabama	N. Dakota	Indiana	Minnesota
Oregon	N. Dakota	Kansas	Washington	Utah	Kansas
Pennsylvania	Alabama	Alabama	Nebraska	W. Virginia	Alabama
Rhode Island	Kansas	Vermont	Hawaii	Kansas	Vermont
Texas	N. Carolina	Minnesota	Florida	Florida	Minnesota
Virginia	Kentucky	Florida	Florida	Kansas	Florida
Arkansas	Louisiana	Missouri	Nebraska	Tennessee	Missouri
Montana	Louisiana	Nebraska	Nebraska	Wisconsin	Nebraska
Nevada	Indiana	Tennessee	Kansas	Georgia	Tennessee
New Mexico	Kentucky	Louisiana	Colorado	Tennessee	Louisiana
Oklahoma	Wisconsin	Iowa	Nebraska	Alabama	Iowa
California	Minnesota	S. Dakota	Alaska	Alabama	S. Dakota

5.9 Adjustments to the Values of the Endogenous Variables in Alberta in the Post-Restructuring Period

Now that best matching jurisdictions have been determined for Alberta and for restructured and non-restructured US jurisdictions, the next step is to use this information to determine appropriate adjustments to the values of the endogenous variables in Alberta in the post-restructuring period, in order to remove the effects that restructuring may have had on these variables, and hence better determine the counterfactual prices.

In the regression model equation used in Chapter 4 to model electricity prices in Alberta in the pre-restructuring period, and to forecast counterfactual electricity prices in the period since restructuring, nine variables were identified as being endogenous, in the sense of their values in the post-restructuring period having potentially been affected by the restructuring process. For one of these, interest rates, which are used as a proxy for the cost of capital, there is no apparent information from US jurisdictions that can be used to modify these values, so they are left unmodified in the subsequent analysis, although this remains an interesting area for subsequent research. Of the remaining eight variables, the three principal variables are coal- and natural gas-based generation capacity and the share of coal-based generation, whereas the other five variables are based on these three primary variables. Specifically, coal and natural gas utilization variables are obtained as a ratio of generation to capacity, while coal and natural gas heat rates are determined as the ratio of fuel consumption to generation. The final endogenous variable is an interaction variable, the product of the coal price and the share of coal based generation.

Among these five secondary endogenous variables, the interaction term is a product of an endogenous variable (share of coal generation) and an exogenous variable (coal price). This means that adjustments determined for the share can be readily used to determine the adjustment to the interaction term. If adjustments to the interaction term were to be computed separately from those for the share, the resulting values for these two variables might not be consistent with each other. However, the four ratio-based secondary endogenous variables each require separate adjustments to be determined because they are each a composite of two other endogenous variables rather than a composite of an endogenous and an exogenous variable. Thus, for example, determining an appropriate adjustment to the value of coal capacity does not indicate what would be an appropriate adjustment to coal utilization because such adjustment depends also on the adjustment to the value of the corresponding generation variable. Of course it would be possible to determine adjustments separately to coal capacity and coal generation, rather than coal capacity and coal utilization, but since it is coal utilization that enters the regression equation, it is preferable to determine the adjustment for this variable directly, as separate adjustments to the two components of this ratio may not result in an appropriate adjustment to the ratio itself.

Thus, to summarize, it is necessary to determine adjustments for the values of seven separate variables that are used in the regression model for Alberta in the post-restructuring period. These seven variables are coal- and natural gas-based generation capacity, the share of coal-based generation, coal and natural gas utilization, and coal and natural gas heat rates. Based on these adjustments, adjustments to the interaction terms can then be determined.

In order to determine the adjustments, and hence the modified values of the Alberta variables in the post-restructuring period, two approaches are used, as discussed previously. First, Alberta values are modified using information based on restructured and non-restructured jurisdictions that are most similar to Alberta. Second, Alberta values are modified based on information concerning differences between how the values of the variables have changed from the pre- to the post-restructuring periods for similar restructured and non-restructured US jurisdictions. Each of these approaches is considered in the following subsections.

5.9.1 Adjustments based on Alberta – US Comparisons

The average values of the seven endogenous variables used in the electricity price model in Chapter 4 – natural gas- and coal-based share of capacity, natural gas- and coal-based heat rates, natural gas- and coal-based utilization ratios, and the share of coal-based generation – are computed for Alberta and Texas for their respective pre- and post-restructuring periods, and for Kansas they are computed for all four of these periods (once for the two periods matching Alberta's pre- and post-restructuring periods, and again for the two periods that match for Texas). The difference in the average values of the pre- and post- restructuring periods is then computed for each restructured jurisdiction. The differences for Alberta and for Texas are then separately subtracted from the Kansas difference figures for the matching periods to yield the difference in differences, *d-i-d*, which denote the impact of restructuring on each of the seven distinct endogenous variables. Details of the calculations of the *d-i-d* values for these seven endogenous variables are shown in Table 5.28 and summarized in Table 5.29. As explained in Section 5.10, these *d-i-d* values are subsequently used to modify the values of the endogenous variables in the post-restructuring period in Alberta.

Table 5.28: The Impact of Restructuring on Endogenous Variables through the Difference in Differences Approach

Year	Coal based capacity share		Natural gas based capacity share		Coal based generation share		Coal based heat rate		Natural gas based heat rate	
	Texas	**Kansas**	**Texas**	**Kansas**	**Texas**	**Kansas**	**Texas**	**Kansas**	**Texas**	**Kansas**
1990	30.23%	53.38%	14.68%	5.97%	50.57%	70.04%	16,161	13,880	11,221	13,417
1991	30.50%	53.35%	14.62%	5.94%	49.54%	72.52%	16,272	13,749	11,120	13,200
1992	31.07%	53.27%	14.50%	5.75%	49.45%	69.74%	16,079	13,876	11,183	14,056
1993	30.52%	53.27%	14.25%	5.54%	51.68%	73.56%	15,670	14,022	11,050	14,122
1994	30.42%	53.49%	14.16%	4.95%	48.08%	71.05%	15,668	13,932	11,170	13,512
1995	30.47%	53.78%	14.00%	4.52%	46.67%	67.74%	15,678	13,680	11,114	13,698
1996	30.39%	53.72%	14.19%	4.52%	48.94%	74.59%	15,323	13,741	10,991	14,063
1997	30.31%	54.37%	14.23%	4.08%	48.95%	71.97%	15,401	13,936	11,129	13,441
1998	30.57%	53.72%	14.06%	4.13%	45.25%	67.56%	15,449	13,615	11,168	13,630
1999	30.57%	52.36%	14.05%	5.34%	47.21%	70.59%	15,304	13,772	11,188	13,408
2000	30.15%	51.69%	14.76%	5.17%	46.38%	72.62%	15,236	13,780	11,191	13,002
2001	32.26%	50.39%	22.27%	7.65%	49.92%	71.16%	14,992	13,610	11,313	13,175
2002	31.94%	49.86%	28.71%	6.08%	60.34%	75.75%	13,847	13,680	11,524	12,988
2003	36.44%	47.59%	24.53%	9.97%	69.39%	76.07%	13,531	13,626	11,119	13,157
2004	35.77%	47.21%	29.17%	9.84%	69.41%	74.54%	13,553	13,481	10,991	13,701
1990-1998 **(A)**	30.50%	53.60%	14.30%	5.05%	48.79%	70.97%	15,745	13,826	11,127	13,682
1999-2004 **(B)**	32.85%	49.85%	22.25%	7.34%	57.11%	73.45%	14,410	13,658	11,221	13,239
% change	7.73%	-6.99%	55.61%	45.52%	17.04%	3.50%	-8.47%	-1.21%	0.84%	-3.24%
difference (post-pre) **(B)-(A)**	2.36 **(C)**	-3.75 **(D)**	7.95	2.30	8.31	2.48	-1,334	-167	93	-443
d-i-d	**-6.10 (D)-(C)**		**-5.66**		**-5.83**		**1,167**		**-537**	

….continued

Table 5.28 (continued)

Year	Coal based utilization ratio		Natural gas based utilization ratio	
	Texas	Kansas	Texas	Kansas
1990	67.73%	46.99%	26.82%	7.08%
1991	66.81%	46.43%	26.96%	9.54%
1992	65.37%	44.81%	25.82%	3.56%
1993	70.65%	54.30%	28.95%	5.50%
1994	67.57%	53.67%	27.87%	7.34%
1995	67.29%	52.47%	27.94%	7.51%
1996	73.40%	60.26%	27.88%	6.03%
1997	75.81%	54.63%	28.34%	7.21%
1998	73.23%	56.34%	33.37%	9.83%
1999	76.24%	60.99%	32.30%	9.35%
2000	76.86%	66.87%	32.90%	9.47%
2001	**73.75%**	65.82%	42.55%	6.38%
2002	79.40%	73.28%	18.41%	5.52%
2003	79.47%	73.24%	20.17%	3.29%
2004	84.22%	72.17%	20.54%	2.24%
1990-1998 **(A)**	69.76%	52.21%	28.22%	7.07%
1999-2004 **(B)**	78.33%	68.73%	27.81%	6.04%
% change	12.27%	31.63%	-1.44%	-14.52%
difference (post-pre) **(B)-(A)**	8.56	16.52	-0.41	-1.03
d-i-d	**7.95**		**-0.62**	

….continued

Table 5.28 (continued)

Year	Coal based capacity share		Natural gas based capacity share		Coal based generation share		Coal based heat rate		Natural gas based heat rate	
	Alberta	**Kansas**	**Alberta**	**Kansas**	**Alberta**	**Kansas**	**Alberta**	**Kansas**	**Alberta**	**Kansas**
1990	73.00%	53.38%	16.00%	5.97%	88.19%	70.04%	11,199	13,880	12,643	13,417
1991	73.00%	53.35%	16.00%	5.94%	89.53%	72.52%	11,917	13,749	12,969	13,200
1992	65.75%	53.27%	23.97%	5.75%	80.91%	69.74%	10,462	13,876	6,085	14,056
1993	65.75%	53.27%	23.79%	5.54%	80.34%	73.56%	11,273	14,022	5,748	14,122
1994	66.42%	53.49%	23.04%	4.95%	81.04%	71.05%	11,307	13,932	6,165	13,512
1995	66.40%	53.78%	23.08%	4.52%	81.84%	67.74%	11,233	13,680	6,510	13,698
1996	66.27%	53.72%	23.07%	4.52%	79.69%	74.59%	11,275	13,741	5,626	14,063
1997	66.22%	54.37%	23.17%	4.08%	79.83%	71.97%	11,218	13,936	6,164	13,441
1998	65.42%	53.72%	23.90%	4.13%	74.84%	67.56%	11,384	13,615	6,380	13,630
1999	63.35%	52.36%	26.09%	5.34%	73.22%	70.59%	11,323	13,772	5,741	13,408
2000	58.00%	51.69%	31.70%	5.17%	69.95%	72.62%	11,137	13,780	7,400	13,002
2001	52.72%	50.39%	37.71%	7.65%	66.76%	71.16%	11,070	13,610	7,069	13,175
2002	50.43%	49.86%	40.45%	6.08%	66.13%	75.75%	11,207	13,680	5,503	12,988
2003	47.81%	47.59%	45.78%	9.97%	66.00%	76.07%	11,127	13,626	5,069	13,157
2004	47.40%	47.21%	45.39%	9.84%	64.00%	74.54%	11,065	13,481	5,623	13,701
1990-1995 **(A)**	68.39%	53.42%	20.98%	5.45%	83.64%	70.77%	11,232	13,856	8,353	13,667
1996-2004 **(B)**	57.51%	51.21%	33.03%	6.31%	71.16%	72.76%	11,201	13,693	6,064	13,396
% change	-15.90%	-4.14%	57.42%	15.87%	-14.93%	2.81%	-0.28%	-1.18%	-27.41%	-1.98%
difference (post-pre) **(B)-(A)**	-10.87 **(C)**	-2.21 **(D)**	12.05	0.86	-12.48	1.99	-31	-163	-2,289	-271
d-i-d	**8.66 (D)-(C)**		**-11.18**		**14.47**		**-132**		**2,018**	

….continued

Table 5.28 (continued)

Year	Coal based utilization ratio		Natural gas based utilization ratio	
	Alberta	**Kansas**	**Alberta**	**Kansas**
1990	74.91%	46.99%	24.83%	7.08%
1991	78.60%	46.43%	21.96%	9.54%
1992	83.04%	44.81%	44.28%	3.56%
1993	84.12%	54.30%	46.10%	5.50%
1994	84.60%	53.67%	46.44%	7.34%
1995	84.98%	52.47%	41.56%	7.51%
1996	82.49%	60.26%	47.31%	6.03%
1997	86.17%	54.63%	49.90%	7.21%
1998	83.81%	56.34%	63.74%	9.83%
1999	81.80%	60.99%	59.79%	9.35%
2000	82.17%	66.87%	56.56%	9.47%
2001	84.80%	65.82%	53.42%	6.38%
2002	85.82%	73.28%	48.95%	5.52%
2003	86.54%	73.24%	39.71%	3.29%
2004	87.34%	72.17%	44.18%	2.24%
1990-1995 **(A)**	81.71%	49.78%	37.53%	6.76%
1996-2004 **(B)**	84.55%	64.85%	51.51%	6.59%
% change	3.48%	30.27%	37.25%	-2.47%
difference (post-pre) **(B)-(A)**	2.84	15.07	13.98	-0.17
d-i-d	**12.23**		**-14.15**	

The *d-i-d* values based on Table 5.28 are summarized in Table 5.29 below.

Table 5.29: Summary of *d-i-d* Values

Jurisdiction	Coal based capacity share	Gas based capacity share	Coal based heat rate	Gas based heat rate	Coal based utilization ratio	Gas based utilization ratio	Share of coal based generation
Texas/ Kansas	-6.1	-5.66	1,167	-537	7.95	-0.62	-5.83
Alberta/ Kansas	8.66	-11.18	-132	-2,018	12.23	-14.15	14.47

5.9.2 Adjustments based on Comparisons of Restructured and Non-Restructured US Jurisdictions

It is clear from Table 5.27 that even based on the three composite variables in columns (7), (8) and (9), a single corresponding non-restructured jurisdiction cannot be determined for each of the restructured jurisdictions. Rather, for each of the 24 restructured jurisdictions at least two different non-restructured jurisdictions match best using the 3 different criteria. As a result, to compute the impact of restructuring on the post-restructuring values of the endogenous variables for each restructured jurisdiction, data from the two or three best matching non-restructured jurisdictions will be utilized. Continuing with the example of Arizona, the three non-restructured jurisdictions that best match Arizona with respect to the capacity, fuel price, and demand composite variables are Florida, Indiana and Georgia respectively.

To determine the impact of restructuring on each of the endogenous variables, the difference-in-differences (*d-i-d*) approach is used. In contrast to just using the difference between the average values of the endogenous variables for two jurisdictions and attributing that difference to restructuring, the benefit of the *d-i-d* approach is that the influence of initial values of endogenous variables that vary between the two types of jurisdictions is removed.[33] Specifically, the *d-i-d* method involves, for each endogenous variable, first computing the difference between the average post-restructuring value and the average pre-restructuring value for the restructured jurisdiction and for each of the matching non-restructured jurisdictions. Next, the difference in these differences is then computed, and attributed to restructuring. In other words, if the difference between the pre- and post-restructuring averages for the restructured jurisdiction is different to the corresponding difference for a non-restructured jurisdiction, this is viewed as being a measure of the effect on that variable of restructuring. Of course, other factors may be at play, particularly random factors that cannot be explicitly taken into account. Indeed, since it is not possible to determine a non-restructured jurisdiction that mimics a restructured jurisdiction on the basis of all

[33] See, for example, Stock and Watson (2007, Ch.13).

three composite variables, technically one cannot attribute the difference in differences solely to restructuring. It is for this reason that a range of these difference-in-differences values is utilized for the subsequent analysis. Specifically, for each endogenous variable, at least two and at most three values of these *d-i-d* computations are determined for each restructured jurisdiction, and these values are subsequently combined for all the restructured jurisdictions in order to obtain a distribution of *d-i-d* values for each endogenous variable. Subsequent adjustments to the values of the endogenous variables in the post-restructuring period in Alberta are then based on the information contained in this distribution, as described later.

Table 5.30 illustrates the *d-i-d* calculations used to determine the impact of restructuring on each of the endogenous variables for Arizona for the period 1990 to 2004 using the matched non-restructured jurisdictions of Florida, Indiana, and Georgia (as determined in Table 5.27). Similar calculations are undertaken for each restructured jurisdiction – excluding California, District of Columbia, Maine, and Rhode Island due to incomplete data for some of the variables, as noted earlier – using its best matching non-restructured jurisdictions.[34]

[34] Computations are not included for matches involving the non-restructured states of Hawaii or Vermont since values of many of the explanatory variables for these two jurisdictions are 0% or missing.

Table 5.30: The Impact of Restructuring on Endogenous Variables through the Difference-in-Differences Approach – Arizona

Year	Share of Coal based capacity				Share of Natural Gas based capacity			
	Arizona	**Florida**	**Indiana**	**Georgia**	**Arizona**	**Florida**	**Indiana**	**Georgia**
1990	34.52%	30.00%	94.52%	60.98%	2.12%	5.24%	0.87%	0.13%
1991	34.87%	30.02%	93.83%	63.51%	1.63%	4.99%	0.86%	0.12%
1992	34.62%	29.40%	93.50%	62.69%	1.62%	5.00%	0.86%	0.12%
1993	34.58%	27.74%	93.06%	62.85%	1.62%	5.32%	0.85%	0.12%
1994	34.46%	27.86%	92.16%	61.57%	1.61%	5.85%	0.86%	0.12%
1995	34.45%	27.82%	90.40%	59.28%	1.10%	6.04%	1.45%	0.11%
1996	34.56%	29.03%	91.70%	59.98%	0.78%	5.91%	1.45%	0.12%
1997	34.54%	29.22%	90.58%	59.11%	0.78%	5.79%	1.49%	0.12%
1998	34.75%	29.19%	91.48%	59.08%	0.22%	5.58%	1.49%	0.12%
1999	34.76%	29.30%	90.62%	58.20%	0.22%	5.16%	1.50%	1.36%
2000	34.82%	28.78%	90.60%	55.64%	0.06%	4.43%	2.51%	3.12%
2001	34.58%	27.87%	90.31%	57.34%	0.73%	5.48%	2.82%	3.99%
2002	33.68%	28.53%	88.55%	53.31%	3.59%	5.37%	5.51%	9.63%
2003	32.80%	23.46%	87.09%	55.01%	6.48%	13.98%	7.06%	7.42%
2004	32.95%	21.84%	86.48%	52.82%	9.31%	15.86%	7.88%	9.20%
1990 – 1997 **(A)**	34.58%	28.89%	92.47%	61.25%	1.41%	5.52%	1.09%	0.12%
1998 – 2004 **(B)**	34.05%	26.99%	89.30%	55.91%	2.95%	7.98%	4.11%	4.98%
% change	–1.52%	–6.55%	–3.42%	–8.71%	109.20%	44.66%	278.24%	4021.56%
difference (post-pre) **(B) – (A)**	–0.53 **(C)**	–1.89 **(D)**	–3.16 **(E)**	–5.33 **(F)**	1.54	2.46	3.02	4.86
d-i-d		**–1.37 (D)-(C)**	**–2.64 (E)-(C)**	**–4.81 (F)-(C)**		**0.93**	**1.49**	**3.32**

….continued

Table 5.30 (continued)

Year	Coal based heat rate				Natural Gas based heat rate			
	Arizona	**Florida**	**Indiana**	**Georgia**	**Arizona**	**Florida**	**Indiana**	**Georgia**
1990	10,920	8,915	10,881	9,024	11,581	11,709	11,769	13,808
1991	10,910	8,899	10,813	9,060	11,559	11,621	11,810	14,862
1992	10,911	8,869	10,711	8,875	11,482	11,642	11,936	16,356
1993	10,793	8,850	10,786	8,733	11,829	10,592	11,590	14,997
1994	10,757	8,850	10,762	9,160	11,861	9,425	11,793	13,920
1995	10,950	8,829	10,879	9,633	11,738	9,888	12,252	14,732
1996	11,351	8,954	10,974	10,001	12,098	9,913	12,515	14,766
1997	11,073	8,973	10,901	10,020	12,189	9,683	12,995	13,918
1998	10,944	9,106	10,771	9,520	12,033	9,586	12,671	13,663
1999	10,825	8,998	10,604	9,196	12,038	9,602	13,193	13,391
2000	10,861	8,874	10,623	9,080	11,980	9,469	12,503	13,167
2001	10,886	9,005	10,591	9,025	12,175	9,615	11,690	11,356
2002	10,873	9,083	10,461	9,016	11,340	8,985	9,532	12,145
2003	10,879	8,879	10,472	9,076	9,919	8,502	9,580	9,984
2004	10,720	8,938	10,367	9,602	9,451	8,319	10,473	8,713
1990 - 1997	10,958	8,892	10,838	9,313	11,792	10,559	12,082	14,670
1998 - 2004	10,855	8,983	10,556	9,216	11,276	9,154	11,377	11,774
% change	–0.94%	1.02%	–2.61%	–1.04%	–4.37%	–13.30%	–5.84%	–19.74%
difference (post-pre)	–103	91	–282	–97	–516	–1,405	–705	–2,896
d-i-d		**194**	**–179**	**6**		**–889**	**–189**	**–2,380**

….continued

Table 5.30 (continued)

Year	Coal utilization ratio				Natural Gas utilization ratio			
	Arizona	**Florida**	**Indiana**	**Georgia**	**Arizona**	**Florida**	**Indiana**	**Georgia**
1990	63.43%	62.14%	50.69%	59.47%	6.81%	13.54%	10.66%	2.32%
1991	64.15%	64.49%	50.96%	47.07%	6.67%	14.55%	12.74%	0.90%
1992	68.71%	64.84%	50.55%	45.69%	8.92%	13.93%	8.85%	1.13%
1993	73.51%	65.11%	52.15%	49.66%	5.74%	11.50%	5.94%	3.46%
1994	75.60%	63.21%	55.14%	50.79%	6.62%	13.22%	7.85%	0.76%
1995	62.97%	64.16%	56.73%	51.90%	5.30%	22.02%	6.42%	4.24%
1996	61.12%	63.72%	55.98%	49.81%	5.32%	19.38%	3.24%	2.55%
1997	67.95%	63.89%	61.05%	51.93%	6.42%	20.90%	3.34%	4.19%
1998	71.93%	63.35%	61.43%	54.82%	11.09%	20.05%	6.77%	13.07%
1999	75.44%	60.65%	62.99%	58.49%	14.57%	22.89%	5.47%	10.18%
2000	80.74%	64.97%	65.40%	61.99%	27.91%	35.94%	4.95%	6.98%
2001	78.89%	61.05%	62.90%	57.49%	29.74%	33.38%	4.17%	6.29%
2002	75.37%	56.19%	61.82%	60.50%	15.31%	38.96%	9.64%	3.63%
2003	74.94%	63.92%	62.35%	61.55%	16.96%	32.17%	8.22%	3.28%
2004	77.71%	65.28%	64.09%	63.16%	17.16%	34.65%	4.27%	5.82%
1990 - 1997	67.18%	63.95%	54.15%	50.79%	6.48%	16.13%	7.38%	2.44%
1998 - 2004	76.43%	62.20%	63.00%	59.71%	18.96%	31.15%	6.21%	7.04%
% change	13.78%	–2.73%	16.33%	17.57%	192.86%	93.10%	–15.84%	187.87%
difference (post-pre)	9.25	–1.75	8.84	8.93	12.49	15.02	–1.17	4.59
d-i-d		**–11.00**	**–0.41**	**–0.33**		**2.53**	**–13.66**	**–7.90**

….continued

Table 5.30 (continued)

Year	Share of Coal based generation			
	Arizona	**Florida**	**Indiana**	**Georgia**
1990	50.79%	47.78%	98.23%	69.25%
1991	48.39%	46.75%	98.30%	66.06%
1992	49.36%	46.00%	98.40%	63.45%
1993	54.42%	44.19%	98.82%	66.11%
1994	53.47%	42.86%	98.61%	65.55%
1995	45.98%	42.04%	98.66%	64.58%
1996	43.43%	45.32%	98.92%	64.04%
1997	43.84%	44.62%	98.59%	65.02%
1998	44.56%	38.64%	98.16%	64.27%
1999	45.72%	37.55%	98.38%	67.01%
2000	46.13%	39.52%	98.24%	68.01%
2001	46.30%	36.90%	98.66%	66.43%
2002	46.45%	33.45%	97.69%	69.10%
2003	46.97%	33.02%	97.73%	67.26%
2004	48.48%	31.05%	98.44%	67.15%
1990 - 1997	48.71%	44.95%	98.57%	65.51%
1998 - 2004	46.37%	35.73%	98.19%	67.03%
% change	–4.79%	–20.49%	–0.39%	2.33%
difference (post-pre)	–2.33	–9.21	–0.38	1.52
d-i-d		**–6.88**	**1.95**	**3.86**

Thus, from Table 5.30 we see that the share of coal-based capacity for Arizona decreased by 0.53 percentage points from its pre-restructuring average to its post-restructuring average. For Florida, the change over the same time period was a decrease of 1.89 percentage points. Thus the *d-i-d* for Arizona-Florida for the share of coal-based capacity is –1.37 percentage points (–1.89 – (–0.53)), indicating that the average in Florida decreased by 1.37 percentage points more than the average in Arizona. For Indiana and Georgia, the corresponding *d-i-d* values are –2.64 percentage points and -4.81 percentage points. Similarly, three sets of *d-i-d* values are obtained for Arizona for each of the other six endogenous variables. Of course for some of the other 19 restructured jurisdictions that are included in this analysis only two alternative sets of *d-i-d* values are obtained due to multiple matches with the same jurisdiction (see Table 5.27). Thus, at most there are 54 *d-i-d* values for each endogenous variable, and in some cases fewer because of missing data.

Table 5.31 presents the *d-i-d* values for each explanatory variable based on the calculations for the 20 restructured jurisdictions. Values for Arizona from Table 5.30 are highlighted. At the foot of the table, summary statistics for the *d-i-d* values for each endogenous variable are presented.

Table 5.31: Difference-in-Difference Values for Endogenous Variables

	Share of coal cap	Share of nat. gas cap	Coal utilization ratio	Nat. gas utilization ratio	Share of coal generation	Coal heat rate	Nat. gas heat rate
1	-21.35	-13.05	-23.32	-20.49	-59.53	-4,843	-5,287
2	-18.90	-12.96	-18.11	-19.91	-57.83	-4,073	-4,962
3	-17.45	-8.82	-18.02	-16.01	-48.05	-949	-4,571
4	-12.12	-7.44	-14.97	-15.79	-36.50	-846	-3,712
5	-9.37	-6.76	-13.95	-15.69	-33.61	-834	-3,484
6	-9.06	-5.71	-12.19	-15.10	-28.68	-773	-3,468
7	-8.10	-5.11	-11.00	-13.87	-17.31	-726	-3,254
8	-6.92	-5.09	-10.43	-13.66	-14.75	-620	-2,380
9	-6.39	-4.50	-9.98	-13.17	-11.86	-589	-2,220
10	-5.98	-3.81	-7.02	-12.80	-10.39	-506	-2,073
11	-5.77	-3.79	-5.24	-7.90	-10.25	-372	-1,976
12	-5.76	-3.73	-2.83	-4.32	-10.15	-351	-1,746
13	-5.67	-3.46	-2.56	-3.97	-7.38	-324	-1,662
14	-5.60	-2.89	-2.09	-3.64	-7.34	-319	-1,464
15	-5.24	-2.70	-0.41	-2.92	-6.88	-316	-1,462
16	-5.03	-2.14	-0.33	-1.85	-6.88	-306	-1,372
17	-4.84	-2.08	0.19	-1.67	-6.63	-290	-1,368
18	-4.81	-1.81	0.47	-1.51	-5.39	-278	-1,240
19	-4.65	-0.80	0.95	-1.16	-5.17	-275	-1,190
20	-4.60	-0.73	1.36	-0.97	-3.88	-260	-1,147
21	-4.23	-0.32	1.52	-0.96	-3.87	-257	-929
22	-3.63	-0.13	1.77	0.06	-3.09	-206	-889
23	-3.14	0.43	1.85	0.44	-0.98	-186	-848
24	-2.64	0.44	2.12	0.62	-0.90	-179	-812
25	-2.46	0.69	2.31	0.69	-0.36	-125	-809
26	-2.03	0.93	2.34	0.80	-0.05	-76	-574
27	-1.93	0.95	2.49	0.90	0.01	-44	-511
28	-1.85	1.49	3.25	1.08	0.03	-33	-448
29	-1.37	2.24	4.44	1.54	0.28	6	-295
30	-1.35	2.29	4.83	1.71	0.94	74	-220
31	-1.17	2.55	4.96	2.10	1.09	182	-218
32	-0.64	2.66	5.52	2.28	1.33	194	-189
33	-0.30	2.72	5.54	2.39	1.80	206	-79
34	-0.03	3.32	5.63	2.53	1.95	391	-44
35	0.24	3.61	7.40	2.64	2.43	398	107

…continued

Table 5.31 (continued)

	Share of coal cap	Share of nat. gas cap	Coal utilization ratio	Nat. gas utilization ratio	Share of coal generation	Coal heat rate	Nat. gas heat rate
36	0.79	3.61	7.87	3.40	2.82	454	116
37	0.81	3.71	8.39	3.59	3.86	474	124
38	1.74	5.08	8.41	3.98	4.34	502	136
39	2.11	6.18	8.59	6.96	5.14	515	199
40	2.24	6.58	8.81	7.42	6.57	604	204
41	2.82	6.85	9.01	8.00	7.78	614	348
42	3.73	9.28	9.09	10.01	8.78	622	554
43	3.78	10.52	9.42	10.51	9.76	808	842
44	4.60	12.62	10.08	11.64	9.77	871	1,012
45	4.78	13.23	12.86	11.95	11.57	873	1,078
46	5.11	13.68	12.96	12.05	11.96	893	1,346
47	16.38	13.73	14.60	12.20	14.84	910	1,354
48	18.30	14.86	15.77	14.76	26.41	945	1,630
49	20.88	15.85	18.85	15.21	27.09	975	1,801
50	22.41	18.20	19.53	15.61	35.42	983	1,928
51	24.62	19.48	22.64	16.84	37.44	1,381	1,941
52	28.29	20.04	26.66	22.31	37.49		15,332
53	30.10		28.20	25.78	43.38		16,379
54	31.23		36.49		44.16		17,631
Mean	0.57	2.31	3.61	0.84	-0.73	-100	133
Median	-1.89	0.94	2.87	0.90	0.02	-76	-480
Max	31.23	20.04	36.49	25.78	44.16	1,381	17,631
Min	-21.35	-13.05	-23.32	-20.49	-59.53	-4,843	-5,287
Count	54	52	54	53	54	51	54

As explained in Section 5.11, these *d-i-d* values are subsequently used to modify the values of the endogenous variables in the post-restructuring period in Alberta.

5.10 Counterfactual Alberta Post-Restructuring Electricity Prices based on Adjustments from Alberta – US Comparisons

In Section 5.9.1, *d-i-d* values were obtained based on Alberta/Kansas and Texas/Kansas comparisons, where Kansas is the non-restructured US jurisdiction that is most similar to Alberta, while Texas is the restructured US jurisdiction that is most similar to Alberta. Thus, to the extent that the endogenous variables are affected in the post-restructuring period, these *d-i-d* values provide an indication of how much these variables were affected by restructuring, so that addition of these *d-i-d* values to the observed Alberta values of the endogenous variables in the post-restructuring period should remove these effects. Subsequent use of these modified values of the Alberta endogenous variables, along with the actual values of the exogenous variables, in the post-restructuring period, in the previously estimated (pre-restructuring) model of the determination of electricity prices in Alberta will therefore allow the counterfactual electricity prices in the post-restructuring period in Alberta to be determined with these effects removed. The results are presented in Section 5.10.1, while sensitivity analysis is provided in Section 5.10.2.

5.10.1 Counterfactual Alberta Post-Restructuring Electricity Prices I

The *d-i-d* values from Table 5.29, based on Alberta/Kansas and Texas/Kansas comparisons, are added to the actual values of the seven endogenous variables for Alberta for each year of the 2001–2005 period to obtain two sets of counterfactual values for the endogenous variables in the post-restructuring period in Alberta. The counterfactual values for the interaction variable in each year are obtained as the product of the counterfactual values of the share of coal based generation and actual coal prices. Based on the counterfactual values of the explanatory variables, the actual values of the exogenous variables and the estimated coefficients for the preferred electricity price model obtained in Chapter 4, the counterfactual electricity prices for Alberta for 2001–2005 are obtained as predictions from the estimated model in the post-restructuring period. These two sets of results – one based on using the Alberta/Kansas restructured – non-restructured jurisdiction pairing, and the other using the *d-i-d* from the Texas/Kansas restructured – non-restructured jurisdiction pairing are presented in Table 5.32.

Table 5.32: Counterfactual Residential Electricity Prices for Alberta, 2001–2005 based on *d-i-d* Modifications to the Endogenous Explanatory Variables from Alberta-US Comparisons

Post restructuring year	Actual Alberta electricity prices (c/kWh)	Predicted Alberta electricity price	
		Texas /Kansas	Alberta /Kansas
2001	9.16	8.35	9.89
2002	10.86	8.57	10.18
2003	10.75	9.29	10.98
2004	10.23	9.13	10.84
2005	10.25	10.32	12.12

Table 5.32 indicates that the counterfactual Alberta electricity prices are below the actual electricity prices for 2001–2004 based on the Texas/Kansas *d-i-d*

figures, and for only 2002 based on the Alberta/Kansas *d-i-d* figures. When compared to the results obtained in Chapter 4, where the endogeneity of the explanatory variables in the post-restructuring period is ignored, the results based on the Texas/Kansas computations confirm the conclusion that electricity prices would have been lower in the absence of restructuring for 2001-2004. However, based on the Alberta/Kansas computations, the opposite result is obtained for the entire 2001–2005 period excluding 2002. In the next section, the effects on these findings of changes to the model specification and to the US jurisdictions that are matched with Alberta are examined.

5.10.2 Sensitivity Analysis I

The results presented in Section 5.10.1 are based on using counterfactual values of the endogenous variables along with actual values of the exogenous variables in each year of the post-restructuring period in Alberta in conjunction with estimated parameters for the model in Chapter 4 that are estimated for the period ending in 2000. There are several components of this analysis where it was necessary to make some choices, and it is important to determine the extent to which, at least qualitatively, the results that were obtained are dependent on these choices. The particular choices that are examined here concern (i) the period and the form in which the model was estimated for the pre-restructuring period in Alberta, and hence the estimated parameters used in the post-restructuring determination of counterfactual electricity prices in Alberta, and (ii) the specific US restructured and non-restructured jurisdictions that are matched with Alberta, and hence the *d-i-d* values that are used to adjust the endogenous variables in Alberta in the post-restructuring period.

In terms of the period and form in which the model was estimated for the pre-restructuring period in Alberta, two alternatives to the preferred model from Chapter 4, estimated in levels for the period 1965 to 2000, are considered. Specifically, the sensitivity of the counterfactual electricity price results is evaluated by alternatively using the parameter estimates from the levels model estimated until 1997, which accounts for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring, and the first-differenced model, estimated for 1966 to 2000, which accounts for non-stationarity of some of the variables.

In terms of the specific US restructured and non-restructured jurisdictions that are matched with Alberta, and hence the *d-i-d* values that are used to adjust the endogenous variables in Alberta in the post-restructuring period, the next best matches from Table 5.21 are considered. The restructured jurisdictions that are considered (in addition to Texas) are Maryland and Oklahoma, while the non-restructured jurisdictions that are considered (in addition to Kansas) are Missouri and North Carolina.

The counterfactual electricity prices for Alberta in the post-restructuring period using Alberta matched with the two other restructured US jurisdictions, and using the different model specifications, are shown in Table 5.33, along with the original results from Table 5.32 (highlighted) for comparison. The counterfactual electricity prices for Alberta in the post-restructuring period using each of the three US restructured jurisdictions matched with one of the three non-restructured US jurisdictions, and using the different model specifications, are shown in Table 5.34, along with the original results from Table 5.32 (highlighted) for comparison.[35]

Table 5.33: Sensitivity Analysis – Alberta/US Non-Restructured Jurisdictions

Post Restructuring Year	Actual Alberta electricity price (c/kWh)	Predicted Alberta electricity price		
		Alberta/ Kansas	Alberta/ Missouri	Alberta/ N. Carolina
(Original) Levels Model Estimated 1965 - 2000				
2001	9.16	9.89	9.56	9.47
2002	10.86	10.18	9.84	9.74
2003	10.75	10.98	10.61	10.52
2004	10.23	10.84	10.46	10.37
2005	10.25	12.12	11.74	11.63
Levels Model Estimated 1965 - 1997				
1998	8.34	9.03	8.75	8.82
1999	8.36	9.70	9.41	9.48
2000	8.86	11.22	10.92	10.97
2001	9.16	11.27	10.96	11.00
2002	10.86	11.85	11.52	11.57
2003	10.75	13.36	13.02	13.06
2004	10.23	13.30	12.96	13.00
2005	10.25	14.79	14.47	14.49
Difference Model Estimated 1966 - 2000				
2001	9.16	8.68	9.68	7.84
2002	10.86	8.94	11.07	6.70
2003	10.75	9.60	12.51	5.90
2004	10.23	9.51	13.55	4.76
2005	10.25	10.25	15.11	3.92

The results in the first panel of Table 5.33, based on the original model, are generally consistent with the results in the last column of Table 5.32, with the counterfactual Alberta electricity prices being below the actual electricity prices

[35] In the case of the differenced models, the predicted prices are obtained by adding the sequence of predicted price changes to the actual price for 2000, the last year of the estimation period. Note that for the differenced model, estimated for 1966 to 2000, the predicted price in 2000, obtained by adding the sequence of fitted price changes for 1966 to 2000 to the actual price in 1965, is the same as the actual price in 2000.

only for 2002 and 2003, compared to only in 2002 previously. The counterfactual prices in the second panel all exceed the actual prices in all years. This may be caused in part by adjusting the values of the endogenous variables in Alberta prior to the period when restructuring actually occurred since estimation here finishes in 1997. The counterfactual Alberta electricity prices in the third panel of Table 5.33 are below the actual prices in all years for two of the three non-restructured jurisdictions that are paired with Alberta to calculate the *d-i-d* values.

The results in Table 5.34, using *d-i-d* values based on comparisons of restructured and non-restructured jurisdictions that are most similar to Alberta, show that using the original model with other pairings of jurisdictions, or using the differenced model with any of the 9 pairings of jurisdictions, the counterfactual electricity prices are below the actual prices in almost all years, except for some jurisdiction pairings with the original (levels) model in 2005. The results for the levels model estimated for the shorter period ending in 1997 are more similar to those using the original levels model with the Alberta / US non-restructured jurisdiction pairings, showing the counterfactual price below the actual price in the post-restructuring period in Alberta only in 2002.

Table 5.34: Sensitivity Analysis – US Restructured /US Non-Restructured Jurisdictions

Post Restructuring Year	Actual Alberta electricity price (c/kWh)	Predicted Alberta electricity price								
		TX/KS	MD/KS	OK/KS	TX/MO	MD/MO	OK/MO	TX/NC	MD/NC	OK/NC
(Original) Levels Model Estimated 1965 - 2000										
2001	9.16	8.35	8.17	8.88	8.14	7.96	8.62	7.98	7.80	8.48
2002	10.86	8.57	8.39	9.14	8.35	8.17	8.85	8.18	8.00	8.71
2003	10.75	9.29	9.12	9.88	9.05	8.88	9.59	8.88	8.70	9.43
2004	10.23	9.13	8.96	9.73	8.89	8.72	9.43	8.71	8.54	9.27
2005	10.25	10.32	10.16	10.95	10.07	9.91	10.64	9.88	9.73	10.47
Levels Model Estimated 1965 - 1997										
1998	8.34	7.72	8.34	7.83	7.42	8.03	7.58	7.52	8.14	7.64
1999	8.36	8.38	9.00	8.48	8.07	8.69	8.23	8.18	8.80	8.29
2000	8.86	9.72	10.42	9.84	9.39	10.10	9.59	9.50	10.20	9.63
2001	9.16	9.66	10.42	9.79	9.31	10.08	9.52	9.42	10.18	9.56
2002	10.86	10.22	11.00	10.35	9.87	10.65	10.07	9.98	10.76	10.11
2003	10.75	11.59	12.43	11.74	11.23	12.07	11.46	11.33	12.17	11.49
2004	10.23	11.52	12.37	11.67	11.15	12.00	11.39	11.26	12.10	11.41
2005	10.25	12.86	13.78	13.03	12.49	13.40	12.75	12.58	13.50	12.77
Difference Model Estimated 1966 - 2000										
2001	9.16	8.51	8.66	8.62	7.60	7.74	7.68	7.69	7.83	7.79
2002	10.86	8.67	8.93	8.88	6.26	6.53	6.42	6.44	6.71	6.64
2003	10.75	9.13	9.54	9.46	5.19	5.60	5.45	5.45	5.86	5.77
2004	10.23	8.90	9.44	9.35	3.83	4.37	4.17	4.18	4.72	4.61
2005	10.25	9.44	10.13	10.00	2.71	3.41	3.16	3.14	3.83	3.69

Overall, the sensitivity analysis tends to confirm the original findings, namely that the counterfactual Alberta electricity prices are below the actual Alberta electricity prices, although this result is much clearer with the difference model, and only applies for adjustments based on some jurisdiction pairings, and mainly in 2002 (for the post-restructuring period), using the levels model estimated for the period ending three years prior to restructuring. In addition, for the original levels model, estimated to 2000, the results are mixed depending on the particular jurisdiction pairings that are used, although the counterfactual prices are less than the actual prices in 2002 and 2003 in almost all cases.

Although it is to be expected that different model specifications will yield somewhat different results, both the original results and those obtained as part of the sensitivity analysis make it difficult to reach a definitive conclusion about the effect of restructuring in Alberta on electricity prices. One of the issues is that it is difficult to know which pairing of jurisdictions, used to obtain the *d-i-d* values and hence the counterfactual values of the endogenous variables, is most appropriate. While the jurisdictions were chosen to be similar to Alberta, as shown in the matching process, the choice of best matching jurisdiction differed according to the criteria (values of variables) used to do the matching, and a number of compromises had to be made in order to determine the best matching jurisdiction. Further, even with the sensitivity analysis that involved some other pairings, it cannot be concluded that the matched US jurisdictions are necessarily closely matched to each other, as they were chosen to match Alberta. A second limitation of this approach is that it involves the determination of a single adjustment to each endogenous variable that is the same in each year of the post-restructuring period.

In view of this uncertainty, rather than trying to decide which set of counterfactual results is most appropriate – by first deciding which match of jurisdictions is most appropriate for determining the *d-i-d* values – a preferable approach may be to determine a distribution for the counterfactual electricity prices based on *d-i-d* values obtained for a variety of different matches. Specifically, instead of obtaining *d-i-d* values based on comparing specific US jurisdictions to Alberta, an alternative approach is to use the *d-i-d* values obtained from matched pairs involving restructured and non-restructured US jurisdictions, as in Section 5.9.2, where again the matching between jurisdictions is based on their electricity generation and consumption environment. As with the matching for Alberta, it was found in Section 5.8 that it was not possible to determine a single best-matching non-restructured jurisdiction for each restructured US jurisdiction, but rather than viewing this as a drawback, this can be viewed as a mechanism that provides a larger number of potential matches and hence *d-i-d* values. As with the method described in Section 5.10.1, each set of *d-i-d* values would be added to the post-restructuring period values of the endogenous explanatory variables in Alberta to yield a set of values for each explanatory variable in each post-restructuring year.

Given the relatively large number of possible values for each explanatory variable in each post-restructuring year that result from this process, rather than obtaining counterfactual electricity prices for each possible combination – which again would raise the problem of choosing between a large set of outcomes – an alternative is to use these values to determine a statistical distribution for each endogenous variable in Alberta in each year of the post-restructuring period. Based on these fitted distributions, Monte Carlo simulations can then be used in conjunction with previously obtained parameter estimates to obtain a distribution for the counterfactual Alberta electricity price in each year of the post-restructuring period. These distributions of counterfactual forecast prices will thus incorporate the uncertainty concerning the values of the endogenous variables in Alberta in the post-restructuring period had restructuring not occurred.

The details of this approach and results obtained are reported below in Section 5.11. Sensitivity analysis is again conducted to determine the extent to which particular choices affect the results in terms of the relationship between the actual and the counterfactual electricity prices in Alberta in the post-restructuring period.

5.11 Counterfactual Alberta Post-Restructuring Electricity Prices based on Adjustments from US Restructured – Non-Restructured Comparisons

In Section 5.9.2, *d-i-d* values were obtained based on calculations for each of 20 restructured jurisdictions matched with as many as three non-restructured US jurisdictions (Table 5.31). These *d-i-d* values provide an indication of how much the endogenous variables were affected by restructuring, so that addition of these *d-i-d* values to the observed Alberta values of the endogenous variables in the post-restructuring period should remove these effects. Subsequent use of these modified values of the Alberta endogenous variables, along with the actual values of the exogenous variables, in the post-restructuring period, in the previously estimated (pre-restructuring) model of the determination of electricity prices in Alberta will therefore allow the counterfactual electricity prices in the post-restructuring period in Alberta to be determined with these effects removed. However, in view of the large number of possible *d-i-d* values for each endogenous variable, and the many possible combinations of these values that could therefore be selected to adjust the values of the Alberta endogenous variables, it is necessary to develop a method that will provide an effective way to proceed. This method and the results that it yields are presented in Section 5.11.1, while sensitivity analysis is provided in Section 5.11.2.

5.11.1 Counterfactual Alberta Post-Restructuring Electricity Prices II

Based on the information in Table 5.31, the values of the endogenous variables in the post-restructuring period in Alberta are modified using information from comparisons of restructured and non-restructured US jurisdictions to remove the likely effect of the restructuring prior to determining the counterfactual electricity prices. However, in contrast to the adjustments based on the Alberta-US comparisons described in Section 5.10.1, in this case the information from the comparisons of restructured and non-restructured US jurisdictions provides a distribution of possible adjustments, so that the approach that is taken is necessarily different.

To begin, each of the d-i-d values in Table 5.31 was added to the actual post-restructuring values of the corresponding endogenous variable in Alberta, for each year in the post restructuring period from 2001 – 2005. This yields a range of the counterfactual values for the respective variables, that is, potential values the endogenous explanatory variables could have taken had restructuring not occurred. These counterfactual values of the seven endogenous variables were inspected to eliminate values that clearly lie outside the feasible range of values for such variables. For example, coal utilization ratios over 100% were eliminated as the ratio of generation to capacity cannot technically exceed 100%. Likewise, values of the share of coal based generation of 100% or greater were eliminated. Moreover, since the share of coal based generation ranged from roughly 30% to 92% between 1965 and 2005, values lower than 20% are viewed as outliers and were also excluded. In addition, the values for US jurisdictions for coal- and natural gas-based heat rates between 1990 and 2004 fall between 8,000 and 20,000 GJ/GWh, whereas for Alberta from 1965 to 2004 these values fell between 5,000 and 16,000 GJ/GWh. Therefore, counterfactual heat rates lower than 5,000 GJ/GWh or higher than 20,000 GJ/GWh were also eliminated.

As a result of this process, for each year in the post restructuring period from 2001 – 2005, a set of counterfactual values for each of the seven endogenous variables was obtained. Technically, it would be possible for each year in this period to choose one counterfactual value for each of these variables and use this in the regression model – along with the observed values of the exogenous variables – to determine the counterfactual electricity price, and then to repeat this process using every possible combination of counterfactual values for the endogenous variables for each year. However, it is likely that some combinations would be inappropriate even though outliers for individual counterfactual values of the endogenous variables have already been excluded. It is also difficult to know which resulting counterfactual electricity prices are appropriate.

An alternative approach is to view the counterfactual values of the endogenous variables as drawings from a distribution of such values. In other words, there is a distribution of possible values of, for example, the share of coal capacity in a particular year, and the set of counterfactual values that have been determined for this variable in this year are values that form part of this distribution. Provided there are enough of these values, it is possible using *Crystal Ball*, an add-on software application to *Microsoft Excel* to determine the appropriate distribution. Here, for every endogenous variable in every year, even with the removal of the outliers, the number of observations is always much greater than the minimum 15 that is required to use this procedure. In each case – for each endogenous variable in each year – *Crystal Ball* computes three test statistics that can be used to determine which of a variety of possible statistical distributions is most appropriate, the Anderson-Darling (AD) test, the Chi-squared (CHI) test, and the Kolmogorov-Smirnov (KS) test, with the statistical distribution that has the lowest value of the test statistic being selected. The distributions that are selected by *Crystal Ball* for each endogenous variable for each year of the post-restructuring period are reported in Table 5.35.

Table 5.35: Specified Distributions of the 7 Endogenous Variables in the Post-Restructuring Period in Alberta based on a Single Set of Counterfactual Values

Distribution Fitting Test	2001	2002	2003	2004	2005
Coal based generation capacity share					
AD	max extreme	max extreme	max extreme	max extreme	max extreme
CHI	logistic	logistic	logistic	logistic	logistic
KS	logistic	logistic	logistic	logistic	logistic
Natural gas based generation capacity share					
AD	max extreme	max extreme	max extreme	max extreme	max extreme
CHI	max extreme	max extreme	max extreme	max extreme	max extreme
KS	student’s t	student’s t	student’s t	student’s t	student’s t
Coal based utilization ratio					
AD	min extreme	min extreme	min extreme	min extreme	min extreme
CHI	beta	beta	beta	beta	min extreme
KS	beta	beta	beta	beta	min extreme
Natural gas based utilization ratio					
AD	student’s t	student’s t	student’s t	student’s t	student’s t
CHI	student’s t	student’s t	student’s t	student’s t	student’s t
KS	student’s t	student’s t	student’s t	student’s t	student’s t
Share of coal based generation					
AD	min extreme	min extreme	min extreme	logistic	logistic
CHI	min extreme	min extreme	min extreme	student’s t	student’s t
KS	logistic	logistic	logistic	logistic	logistic
Coal based heat rate					
AD	triangular	triangular	triangular	triangular	triangular
CHI	beta	beta	beta	beta	beta
KS	weibull	weibull	weibull	weibull	weibull
Natural gas based heat rate					
AD	weibull	gamma	gamma	gamma	weibull
CHI	lognormal	gamma	beta	weibull	normal
KS	weibull	gamma	gamma	gamma	weibull

As can be seen from Table 5.35, in many cases the preferred distribution differs depending on the test statistic considered. Since the Anderson Darling test is widely used in fitting distributions,[36] the distributions identified through the criterion of the lowest Anderson Darling (AD) statistic are selected for the simulation analysis. In this analysis, for each post-restructuring year *Crystal Ball* is used to make a random selection from the specified distribution for each endogenous variable. In addition, the selected value for the share of coal-based generation is multiplied by the actual coal price to yield a value for the endogenous interaction variable. These values for the eight endogenous variables, along with the actual values of the six exogenous variables, are used with the estimated coefficients for the preferred electricity price model obtained in Chapter 4 to obtain the counterfactual electricity price for Alberta as a prediction from the estimated model in the post-restructuring period. This Monte Carlo simulation process, beginning with the random selection of values from the statistical distribution for each endogenous variable and ending with the counterfactual forecast electricity price, is repeated a large number of times for each year of the post-restructuring period, thereby yielding a distribution for the counterfactual electricity price in Alberta in each of these years. These results are summarized in Table 5.36.

Table 5.36: Counterfactual Residential Electricity Prices (c/kWh) for Alberta, 2001–2005 based on Monte Carlo Simulations

Post restructuring year (1)	Actual Electricity price (2)	Mean of electricity price forecasts (3)	Mean based on distribution fit on price forecasts (4)	% of price forecasts less than actual electricity price (5)	Distribution fitted on price forecasts (6)
2001	9.16	8.66	8.55	70.58%	logistic
2002	10.86	9.04	8.91	89.74%	logistic
2003	10.75	9.71	9.62	79.46%	logistic
2004	10.23	9.48	9.35	74.56%	logistic
2005	10.25	10.64	10.53	42.31%	Student's t

Column (3) of Table 5.36 indicates that the mean of the electricity price forecasts – the counterfactual electricity prices – obtained through simulations is lower than the actual electricity price (shown in Column (2)) for each of the post restructuring years from 2001–2004. When distributions were fit on the electricity price forecasts, the mean electricity price from these distributions were also lower than the actual electricity price for 2001–2004. In fact, as shown in Column (5) of this table, 70% or more of the counterfactual electricity prices were lower than the actual electricity prices. This result would appear to lend solid support to the claim that electricity prices would have been lower for the 2001–

[36] Decisioneering Inc. (2004), Introduction to Crystal Ball, Training Work Book, (Denver, Colorado: Decisioneering Inc.).

2004 period had electricity market restructuring not taken place in Alberta. It is only in 2005 that this result is reversed.

5.11.2 Sensitivity Analysis II

The results presented in Section 5.11.1 are based on using counterfactual values of the endogenous variables along with actual values of the exogenous variables in each year of the post-restructuring period in Alberta in conjunction with estimated parameters for the model in Chapter 4 that is estimated for the period ending in 2000. In addition, the results are based on treating the (up to) 54 sets of *d-i-d* values obtained for each endogenous variable as though they come from the same underlying distribution even though they are based on matches based on as many as three different composite variables. This is a relatively strong assumption, as the different matches are not necessarily equivalent. Therefore, to conclude the analysis it is appropriate to determine the sensitivity of the results to both these assumptions to ensure that the results are not simply contrived by the particular choices that were made.

To examine the sensitivity of the results presented in Section 5.11.1 to relaxing the assumption that the (up to) 54 sets of *d-i-d* values obtained for each endogenous variable come from the same underlying distribution, the sets of *d-i-d* values are separated into three groups based on the particular composite variable that was used to form the matches – generation and capacity, fuel price, and electricity demand. For each group this yields as many as 19 or 20 sets of *d-i-d* values. Treating each group separately, these *d-i-d* values are then added to the actual post-restructuring values of the seven endogenous variables for each year of the post restructuring period from 2001–2005. As before, this procedure yields a range of counterfactual figures for the potential values the explanatory variables could have taken in each of these years had restructuring not taken place. Again, these counterfactual values of the seven endogenous variables are inspected to eliminate values that clearly lie outside the feasible range of values for such variables. Next, *Crystal Ball* is used to fit statistical distributions to the remaining counterfactual values for each year for each endogenous variable, and a final distribution is selected based on the lowest value for the Anderson Darling test.[37] The 105 distributions that are selected by *Crystal Ball* based on this test are reported in Table 5.37. As can be seen from this table, in many cases different distributions are selected for a particular explanatory variable in a particular year using the counterfactual values based on the different composite variables. A comparison with Table 5.35 indicates that, in many cases, a different distribution is now selected for specific endogenous variables.

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[37] Crystal Ball requires at least 15 observations to fit a distribution, but for 2002–2004 for the natural gas-based heat rate variable and for 2004 for the coal-based utilization ratio variable, fewer than 15 counterfactual values were available once outlying values were eliminated. In these cases, the distributions identified in Table 5.35 were used.

Table 5.37: Specified Distributions of the 7 Endogenous Variables in the Post-Restructuring Period in Alberta based on Three Sets of Counterfactual Values

Composite variable	2001	2002	2003	2004	2005
Coal based generation capacity share					
Generation and capacity	max extreme	max extreme	max extreme	max extreme	logistic
fuel price	max extreme	max extreme	max extreme	max extreme	max extreme
Electricity demand	max extreme	max extreme	max extreme	max extreme	max extreme
Natural gas based generation capacity share					
Generation and capacity	lognormal	lognormal	lognormal	lognormal	lognormal
fuel price	max extreme	max extreme	max extreme	max extreme	max extreme
Electricity demand	max extreme	max extreme	gamma	max extreme	max extreme
Coal based utilization ratio					
Generation and capacity	triangular	triangular	triangular	weibull	triangular
fuel price	min extreme	min extreme	min extreme	min extreme	min extreme
Electricity demand	min extreme	min extreme	min extreme	min extreme	logistic
Gas based utilization ratio					
Generation and capacity	Student's t	Student's t	Student's t	Student's t	Student's t
fuel price	logistic	logistic	logistic	logistic	logistic
Electricity demand	beta	beta	beta	beta	beta
Share of coal based generation					
Generation and capacity	min extreme	min extreme	min extreme	min extreme	min extreme
fuel price	min extreme	min extreme	min extreme	Student's t	Student's t
Electricity demand	logistic	logistic	logistic	logistic	logistic
Coal-based heat rate					
Generation and capacity	max extreme	max extreme	max extreme	max extreme	max extreme
fuel price	max extreme	max extreme	max extreme	max extreme	max extreme
Electricity demand	beta	beta	beta	beta	beta
Natural Gas-based heat rate					
Generation and capacity	beta	gamma	gamma	gamma	beta
fuel price	weibull	gamma	gamma	gamma	weibull
Electricity demand	Student's t	gamma	gamma	gamma	Student's t

Based on the distributions of the values of the counterfactual explanatory variables in Table 5.37, counterfactual electricity prices for each year of the post-restructuring period are obtained through Monte Carlo simulations as described previously. The results, reported in Table 5.38, confirm the earlier findings in Table 5.36 that the mean of the distribution of the counterfactual electricity prices is centred below the actual electricity price for the post restructuring period from 2001–2004. This result, as before, changes for the year 2005. Thus, it appears that treating the counterfactual values of the explanatory variables as having emerged from a single distribution versus having emanated from three separate underlying distributions for each of the post-restructuring years from 2001–2005 has virtually no bearing on the counterfactual electricity price results.

Table 5.38: Counterfactual Residential Electricity Prices (c/kWh) for Alberta, 2001 – 2005 based on Three Sets of Counterfactual Values

Post restructuring year	Actual electricity price	Mean of electricity price forecasts	% of price forecasts less than actual electricity price
Generation and Capacity Composite Variable			
2001	9.16	8.68	69.74%
2002	10.86	8.88	91.76%
2003	10.75	9.80	78.57%
2004	10.23	9.40	75.69%
2005	10.25	10.49	41.86%
Fuel Price Composite Variable			
2001	9.16	8.59	73.79%
2002	10.86	8.73	95.02%
2003	10.75	9.50	84.76%
2004	10.23	9.36	77.94%
2005	10.25	10.62	43.98%
Electricity Demand Composite Variable			
2001	9.16	8.73	68.69%
2002	10.86	8.99	90.71%
2003	10.75	9.68	79.91%
2004	10.23	9.60	71.50%
2005	10.25	10.84	37.35%

Finally, the sensitivity of the counterfactual electricity price results from Section 5.11.1 is evaluated by alternatively using the parameter estimates from the levels model estimated until 1997, which accounts for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring, and from the first-differenced model which accounts for non-stationarity of some of the variables. For the purpose of this analysis, the distributions determined via the Anderson-Darling statistic in Table 5.35 are used. The results from the simulation analysis in these cases are reported in Table 5.39.

Table 5.39: Counterfactual Residential Electricity Prices (c/kWh) for Alberta, 2001 – 2005 based on Alternative Electricity Price Determination Models

Post restructuring year	Actual electricity price	Mean of electricity price forecasts	% price forecasts < actual electricity price
Levels Model estimated 1965 - 1997			
1998	8.34	6.4798	92.70%
1999	8.36	7.0585	87.80%
2000	8.86	7.7099	83.95%
2001	9.16	7.1723	93.18%
2002	10.86	7.6800	97.36%
2003	10.75	8.4582	92.90%
2004	10.23	8.3420	90.03%
2005	10.25	9.5348	73.77%
Difference Model estimated 1966 - 2000			
2001	9.16	8.6446	70.67%
2002	10.86	8.9094	97.60%
2003	10.75	9.4580	89.78%
2004	10.23	9.4790	78.67%
2005	10.25	10.1596	54.76%

The results from the levels model estimated until 1997 yields a stronger result than the base case, in that the mean of the distribution of the counterfactual electricity prices is centred below the actual electricity price for the entire post restructuring period from 1998–2005. Thus, in this case there is no reversal of results for 2005. Likewise, the first-differenced model yields stronger results compared to the base case in that the mean of the distribution of the counterfactual electricity price differences is centred below the actual electricity price difference for the entire post restructuring period from 2001 to 2005. For the period 2001 to 2004, between 70% and 98% of the counterfactual electricity prices were below the actual electricity price, although this percentage drops to approximately 55% in 2005. Effectively, the results from the various simulations support the finding of the initial analysis in Section 5.11.1 that post-restructuring electricity prices in Alberta have been higher relative to what they would have been had electricity market restructuring not been pursued.[38]

[38] Since this result contrasts with the findings of the only other study of restructuring in Alberta that uses a counterfactual approach, a critical assessment of the main arguments advanced by this other study (Wellenius and Adamson, 2003, and an update by Wellenius, 2004) in the context of the results and analysis in this chapter is provided in Appendix 5.2.

5.12 Summary and Conclusion

The focus of this chapter is on modifying the post-restructuring period values of the eight explanatory variables used in the model developed in Chapter 4 to account for the potential impacts on these variables from the restructuring that occurred. Specifically, other Canadian and US jurisdictions were examined to determine if the values of the explanatory variables in Alberta in the post-restructuring period could be replaced with values from one of these other non-restructured jurisdictions. As an alternative, restructured and non-restructured US jurisdictions were compared to determine the likely effect of electricity industry restructuring on the explanatory variables, with a view to modifying the observed values of these variables in Alberta in the post-restructuring period to adjust for these effects. After removing the potential impact of restructuring from the actual post-restructuring Alberta values of the explanatory variables, through the difference in differences approach, new sets of counter-factual electricity prices were constructed and compared with the prices that were actually observed in Alberta in the post-restructuring period. These new sets of counterfactual electricity prices are viewed as an improvement on the counterfactual electricity prices based on the naïve approach used in Chapter 4.

It was found in Section 5.2 that the generation capacity share mix and external conditions (based on fuel prices and real GDP growth) in Canadian non-restructured provinces were dissimilar enough to Alberta that they could not be used to isolate the impact of restructuring on explanatory variables used in the model developed in Chapter 4. From Section 5.3 onwards, the focus was therefore on US jurisdictions. For the purposes of analysis, 27 of these US jurisdictions were considered to be non-restructured while 24 had restructured their electricity markets. For subsequent analysis, the date at which these jurisdictions restructured was based on the year of the restructuring legislation enactment or the issuing of the regulatory order at the retail level. A general analysis of these different US jurisdictions was undertaken in Section 5.5 and 5.6 prior to developing the difference in differences (*d-i-d*) approach that was used to construct counterfactual electricity prices in Section 5.7 onwards. The primary motivation for this general analysis was to determine whether particular attention should be paid to certain of these variables when making adjustments to the Alberta values in the post-restructuring period.

This general analysis of the US data in Section 5.5 revealed that from the pre- to the post-restructuring period as defined, average residential electricity prices have statistically and significantly increased at a higher rate in the non-restructured jurisdictions relative to the restructured jurisdictions. Moreover, average electricity prices actually fell in the post-restructuring period in 8 restructured jurisdictions compared to only 4 of the non-restructured jurisdictions in the post-1996 period. It is possible that the greater percentage decline in electricity prices in the 8 restructured jurisdictions might be specifically explained by restructuring initiatives directed towards reducing nuclear capacity. On the other hand, the analysis indicated that there has been a greater efficiency increase in natural gas-based plants and greater utilization of coal-based plants in the Category A non-restructured jurisdictions (those where electricity prices fell in the post 1996 period), compared to in Category C restructured jurisdictions (those where electricity prices fell post-restructuring), which seems to indicate that, absent restructuring initiatives, capacity composition and efficiency-enhancing technology may reduce electricity prices.

However, no definitive conclusions can be made on the basis of this preliminary analysis since it does not control for the effect of changes in principal variables such as generation capacity, fuel consumption mix and fuel prices. Thus, based on this preliminary analysis, all that may be concluded is that lower electricity prices are associated with a greater dependence on coal-based capacity and generation, smaller shares of average natural gas-based capacity and generation, lower natural gas capacity utilization figures, lower fuel prices and lower average real GDP growth.

In Section 5.6, electricity prices and the values of various explanatory variables in Alberta were compared with those observed in various US jurisdictions. This analysis indicated that Alberta electricity prices seem to be more strongly correlated with some of the non-restructured jurisdictions than the restructured ones, and that in terms of having higher coal-based shares of capacity and generation, Alberta is more similar to the non-restructured jurisdictions, specifically those where electricity prices fell in the post 1996 period. Moreover, given the absence of nuclear-based capacity in Alberta, and its small percentage of hydro-based capacity, any role of restructuring related to nuclear- and hydro-based capacity in the US is essentially irrelevant in the context of Alberta. In terms of external conditions, fuel prices are much lower in Alberta compared to both types of US jurisdictions, although increases in real GDP growth and higher levels of HDDs tend to indicate a higher electricity demand in Alberta.[39]

Section 5.7 and Section 5.8 build toward developing the d-i-d framework by narrowing down the variables identified in Section 5.5 to three composite variables that captured capacity and generation, electricity demand, and fuel prices. Eventually, Texas and Kansas were identified as the regulated and non-regulated jurisdictions, respectively, that best match Alberta. However, it was noted in Section 5.9 that since it was not possible to determine a non-restructured jurisdiction that mimicked a restructured jurisdiction on the basis of all three composite variables, technically one could not attribute the observed difference in differences solely to restructuring. It is for this reason that a range of these difference-in-differences values were utilized in the subsequent analysis.

In Section 5.10, the d-i-d values determined in Section 5.9, based on Alberta/Kansas and Texas/Kansas comparisons, were added to the actual values of the endogenous variables for Alberta for each year of the 2001 to 2005 period

[39] Again, ignoring CDDs, as discussed earlier.

to obtain two sets of counterfactual electricity prices. When compared to the results obtained in Chapter 4, where the endogeneity of the explanatory variables in the post-restructuring period is ignored, the results based on the Texas/Kansas computations confirm the conclusion that electricity prices in Alberta would have been lower in the absence of restructuring for 2001-2004. However, based on the Alberta/Kansas computations, the opposite result is obtained for the entire 2001–2005 period excluding 2002. Sensitivity of the counterfactual electricity price results was evaluated by alternatively using the parameter estimates from the levels model estimated until 1997, which accounts for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring, and the first-differenced model, estimated for 1966 to 2000, which accounts for non-stationarity of some of the variables. Sensitivity of the counterfactual electricity price results was also evaluated by using d-i-d figures based on jurisdiction correspondences other than Kansas and Texas.

Overall, the sensitivity analysis confirmed the original findings, namely that the counterfactual Alberta electricity prices are below the actual Alberta electricity prices, although this result is much clearer with the difference model, and only applies for adjustments based on some jurisdiction pairings, and mainly in 2002 (for the post-restructuring period) using the levels model estimated for the period ending three years prior to restructuring. In addition, for the original levels model, estimated to 2000, the results are mixed depending on the particular jurisdiction pairings that are used, although the counterfactual prices are less than the actual prices in 2002 and 2003 in almost all cases. Although it is to be expected that different model specifications will yield somewhat different results, both the original results and those obtained as part of the sensitivity analysis make it difficult to reach a definitive conclusion about the effect of restructuring in Alberta on electricity prices.

An important issue that arises with the analysis in Section 5.10 is that it is difficult to know which pairing of jurisdictions used to obtain the *d-i-d* values and hence the counterfactual values of the endogenous variables is most appropriate, as a number of compromises had to be made in order to determine the best matching jurisdiction. Moreover, a second limitation of this approach is that it involved a single adjustment to each endogenous variable that is the same in each year of the post-restructuring period. To overcome these limitations, in Section 5.11, a Monte Carlo approach was used, based on a distribution of adjustments to values of explanatory variables that is determined from the *d-i-d* values obtained for a variety of different US restructured/non-restructured jurisdiction matches. With this approach, the endogenous variables are treated as having values based on underlying distributions, and this allows – via simulation analysis – the determination of a distribution for the counterfactual electricity prices for each of the post restructuring years in Alberta. Based on this simulation analysis, the mean of the counterfactual electricity prices was found to be lower than the actual electricity price for each of the post restructuring years from 2001–2004 except 2005. Moreover, the result that 70% or more of the counterfactual electricity prices were lower than the actual electricity prices for 2001 – 2004 lent solid support to the claim that electricity prices would have been lower for the 2001–2004 period had electricity market restructuring not taken place in Alberta.

Sensitivity of the distribution of counterfactual electricity price results was evaluated by treating the counterfactual values of the explanatory variables as having emanated from three separate underlying distributions, based on the three composite variables (generation and capacity, fuel prices and electricity demand), for each of the post-restructuring years from 2001–2005 as opposed to assuming that the counterfactual values of the explanatory variables emerged from a single distribution. The results appeared robust to this sensitivity analysis as well as to the sensitivity analysis that was evaluated by alternatively using the parameter estimates from the levels model estimated until 1997, which accounted for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring. In fact, the results from the levels model estimated until 1997 yielded a stronger result than the base case, in that the mean of the distribution of the counterfactual electricity prices is centred below the actual electricity price for the entire post restructuring period from 1998–2005. Likewise, the sensitivity analysis based on the first-differenced model, which accounts for the possible non-stationarity of some of the variables, yielded stronger results compared to the base case in that the mean of the distribution of the counterfactual electricity price differences is centred below the actual electricity price difference for the entire post restructuring period from 2001-2005. Effectively, the results from the different simulations support the finding that post-restructuring electricity prices in Alberta have been higher relative to what they would have been had electricity market restructuring not been pursued.

Appendix 5.1: Description of Data Availability, Anomalies, and Large Changes in Values of Explanatory Variables for US Jurisdictions

For many US jurisdictions, values of the explanatory variables are missing for some years, or appear to contain particular anomalies, or undergo extremely large changes from one year to the next. In this appendix these features are summarized in Tables A5.1.1 to A5.1.5. Also, since values of these variables are utilized in jurisdictional comparisons, a more detailed analysis is provided for some of the jurisdictions identified in Tables A5.1.1 to A5.1.5.

Tables A5.1.1 to A5.1.5 contain four categories – "Change", 0% or 0, 100%, and "Oddities". Here "change" refers to a drastic shift in the data for some jurisdictions after a certain year, while 0% or 0, and 100% refer to the fact that some jurisdictions have 0% or 0 or 100% as values for the respective variables. The category "oddities" indicates any odd or unique aspect of the data, such as an unexpected value of zero for a particular year, or negative values for any of the variables. For Tables A5.1.4 and A5.1.5, "N/A" refers to the fact that the data are unavailable or that they cannot be computed because the denominator is zero in the variable computation.

Table A5.1.1: Fuel Consumption

Restructured Jurisdictions*			
Issue	**Coal consumption share**	**Natural gas consumption share**	**total fuel consumption**
change	CT (1998) 0% from 1999	CT 100% in 1999, 0% from 2000	CT 0 GJ from 2000
	DE (1999) 0% from 2002	DE 100% from 2002	
	MD (1999) 0% from 2001	MD 100% in 2001, 0% from 2002	MD 0 GJ from 2002
		RI (1996) 100% till 1998, 0% from 1999	RI 0 GJ from 1999
0%	DC, ME, RI, CA	DC, ME	DC, ME
100%		CA	
oddities	MA (1997) 0% in 2002	MA 100% 2002	
	NH (1996) 100% from 1990-1991 and 2003 - 2004	NH 0% from 1990-1991 and 2003-2004	
Non-Restructured Jurisdictions			
Issue	**Coal consumption share**	**Natural gas consumption share**	**total fuel consumption**
change	WA 0% 2001 onwards	WA 100% from 2001	
		ID 0% till 2001, 100% from 2002	ID 0 GJ till 2001
0%	HI, ID, VT	HI, ND,	HI
100%	ND	VT	
oddities			

* The values in parentheses refer to the year of electricity market restructuring legislation.

Table A5.1.2: Capacity

Issue	coal capacity share	hydro capacity share	natural gas capacity share	nuclear capacity share	total capacity
Restructured Jurisdictions					
Issue	**coal capacity share**	**hydro capacity share**	**natural gas capacity share**	**nuclear capacity share**	**total capacity**
change	CT 0% from 1999		CT 0% till 1993, 0% from 1999	CT 0% from 2001	
	DE 0% from 2002		DE 0% from 2000		
	MD 0% from 2000	MD 0% from 2001	MD 0% from 2000	MD 0% from 2000	
			RI 0% 1990, 1992-1994 and from 1998		
		ME (1997) 0% from 2001		ME 0% from 1997	
			NJ (1999) 0% from 2000	NJ 0% from 2000	
			PA (1996) 0% from 2002		
			MT (1997) 0% from 1997		
				IL (1997) 0% from 2001	
				MA 0% from 1999	
				NH (1996) 0% from 2001	
				OR (1999) 0% from 1993	
				TX (1999) 0% from 2003	
					DC 0 MW from 2000
0%	DC, ME, RI, CA	DE, DC, NJ	DC, ME, NH,	DE, DC, RI, MT, NV, NM, OK	
100%					
oddities			MA 0% in 2004	NY 0% in 2004	
Non-restructured Jurisdictions					
Issue	**coal capacity share**	**hydro capacity share**	**natural gas capacity share**	**nuclear capacity share**	**total capacity**
change	WA 0% from 2000		WA 0% till 1996		
			ID 0% till 1993		
			WY 0% till 1999		
				VT 0% from 2001	
0%	HI, ID, VT	KA, LA, MS	TN, VT, WV	AK, CO, HI, ID, IN, KY, ND, SD, UT, WV, WY	
100%					
oddities			AL 0% in 1990		

Table A5.1.3: Generation

Issue	coal generation share	hydro generation share	natural gas generation share	nuclear generation share	total generation
Restructured Jurisdictions					
change	CT 0% from 1999		CT 0% from 2000	CT -ve in 1997, 0% from 2002	
	DE 0% from 2002				
	MD 0% from 2001	MD 0% from 2001	MD 0% from 2002	MD 0% from 2001	
		ME 100% in 2000, 0% from 2001		ME 0% from 1997	
			NH 0% from 1990-1991, 1996, 2003 - 2004		
			RI 0% from 1999		
				IL 0% from 2001	
				MA 0% from 2000	
				NH 0% from 2003	
				NJ 0% from 2001	
				OR -ve in 1993, 0% from 1994	
				TX 0% from 2003	
					DC from 2001
0%	DC, ME, RI, CA	DE, DC, NJ, RI,	DC, ME	DE, DC, RI, MT, NV, NM, OK	
100%					
oddities	MA 0% in 2002		PA (2001) 0% in 2001		ME 0 MWh in 2001
	NJ 109.21% in 2004				RI 0 MWh in 2001
Non-restructured Jurisdictions					
Issue	**coal generation share**	**hydro generation share**	**natural gas generation share**	**nuclear generation share**	**total generation**
change	WA 0% from 2001		ID 0% from 1990 - 2001		
			VT 0% 1996 - 1997	VT 0% from 2003	
0%	HI, ID, VT	KA, LA, MS	HI	AK, CO, HI, ID, IN, KY, ND, SD, UT, WV, WY	
100%		ID			
oddities			ND -ve values		

Table A5.1.4: Heat Rates and Capacity Utilization

Restructured Jurisdictions					
Issue	**coal-based heat rate**	**natural gas-based heat rate**	**coal-based utilization**	**natural gas-based utilization**	**heating degree days**
change	CT from 1999	CT from 2000	CT from 1999	CT from 1999	
	DE from 2002		DE from 2001		
	MD from 2001	MD from 2002	MD from 2000	MD from 2000	
		RI from 1999		RI from 1998	
				NH from 2000	
N/A	DC, ME, RI, CA	DC, ME	DC, ME, RI, CA	DC, ME,	DC
oddities	MA N/A in 2002	NH N/A 1990 - 1991	MA 0% in 2002	DE N/A 2000-2001	
Non-restructured Jurisdictions					
Issue	**coal-based heat rate**	**natural gas-based heat rate**	**coal-based utilization**	**natural gas-based utilization**	**heating degree days**
change	WA from 2001		WA from 2000		
		ID till 2001		ID N/A till 2003, 0% from 1994 - 2001	
				WY till 1999	
N/A	HI, ID, VT	HI	HI, ID, VT	HI, VT, WV	AK, HI
oddities		ND -ve values 1990 - 1995, 2003, 0 1998 - 2000		ND -ve values till 1995, 1998 - 2000, 2003	

Table A5.1.5: HDD, Fuel Prices and Wage/Worker

Restructured Jurisdictions				
	HDD	**natural gas price**	**coal price**	**wage/worker**
N/A	DC	DC	ME, RI	DE 1969 - 1997
		CT 1973, 1977-1983, 2000-2001, 2003-2004	CT from 2000	DC till 1998, 2001, 2002
		DE from 2002	DE from 2002	RI 2001, 2002
		ME 1967-1970, 1980-2001, 2004	DC 1985-1999, 2001-2004	
		MD 2001, 2004	MD from 2001	
		MI 2004	MA 2001	
		NH 1967-1980, 1982-1983, 1985-1986,		
		1990-1991, 1996, 1998, 2003-2004		
		NJ 2004		
		OH 2004		
		OR 1978, 1985-1990, 2004		
		PA 2004		
		RI 1977, 1978, 1986, 1999-2001		
		VA 2004		
		AR 2004		
		MT 1997, 2004		
		NM 2002-2004		
		OK 2004		
Non-restructured Jurisdictions				
	HDD	**natural gas price**	**coal price**	**wage/worker**
N/A	AK, HI	HI	AK, HI, ID, VT	NC 2001
		AL 2004	WA from 2001	VT 1998
		AK 2002		WY 2001, 2002
		GA 2004		
		ID 1967-1973, 1987-2004		
		IN 2004		
		KY 2003-2004		
		MN 2002-2004		
		MS 2004		
		MO 2002-2004		
		NC 2004		
		ND 1998-2000, 2003		
		SC 2002-2004		
		SD 1997, 1999-2004		
		TN 1974-1975, 1977-1979,		
		1984-1987, 1997-2004		
		UT 2002, 2004		
		VT 1967-1979, 1987, 2002-2004		
		WA 1967-1977, 1999-2002, 2004		
		WV 2004		
		WI 2004		

As the information in Tables A5.1.1 to A5.1.5 shows, for several states that restructured their electricity markets, the values of variables such as capacity, generation, and fuel consumption underwent very large changes in the post-restructuring period. These changes directly affect the values of variables such as heat rates and capacity utilization in Table A5.1.4. The years in parentheses beside the US jurisdiction abbreviations in the tables indicate when the restructuring legislation was passed, which is also used here to distinguish between the pre- and post-restructuring periods.

Since values of these variables are utilized in jurisdictional comparisons, in what follows, for some of the jurisdictions identified in Tables A5.1.1 to A5.1.5, a detailed analysis is provided below.

Connecticut

While restructuring legislation or a regulatory order was passed in 1998 for Connecticut, total fuel consumption – the sum of coal and natural gas consumption – fell to 0 GJ in 2000, and coal- and natural gas-based capacity fell to 0 MWh in 1999, although according to the data while coal consumption fell to 0% of fuel consumption in 1999, natural gas was employed in 1999, thereby forming 100% of fuel consumption in 1999. This fact however, does not take into account the use of other fuels like petroleum. Coal and natural gas prices are unavailable from 2000 onwards, except for 2002 when the natural gas price is available. Thus, it seems that in 1999, one year prior to termination of fuel consumption of both coal and natural gas, there was a drastic shift to natural gas consumption.

Coal-based generation falls to 0% of total generation, however, natural gas-based generation was still about 5.76% of total generation in 1999 despite the fact that according to the data, natural gas-based capacity was 0 MWh in 1999. This can perhaps be explained by the fact that natural gas-based capacity changed in the latter part of 1999, and is recorded as such, whereas generation data is based on what actually was generated in 1999. This observation may also help in explaining why coal-based capacity utilization is greater than 100% in several other US jurisdictions.

While for 1999 there appears to be a shift from coal-based generation to natural gas-based generation, this shift is not large, as the pre-restructuring shares of coal- and natural gas-based capacity are only 5.67% and 2.14%, respectively. The changes in coal- and natural gas-based capacity shares, generation shares, and consumption shares do not matter much, although the pre-restructuring nuclear based capacity share is a substantial 46.29%, which fell to 0% in 2001. In fact, both total generation and total capacity fell in the post-restructuring period, specifically from 2001 onwards.

These observations do not allow us to make strong conclusions on the shift in the type of generation and capacity, but mostly allow us to conclude that in the post-restructuring period, domestic capacity and generation became relatively minuscule – average total capacity fell from 6,178 MW (1990 – 2000) to 172 MW (2001 – 2004), average total generation fell from 22,300,988 MWh (1990 – 2000) to 735,799 MWh (2001 – 2004) - indicating that perhaps imports were used to satisfy the bulk of Connecticut's electricity demand. The changes in capacity, generation and consumption of coal and natural gas affect the respective heat rates and capacity utilizations in the post-restructuring period. However, these changes are not important given the low shares of coal- and natural gas-based capacity.

Given the significant change in the nuclear-based capacity share in 2001, it is tempting to distinguish between the pre- and post-restructuring periods on the basis of the year of retail access, 2000, as opposed to the passing of legislation. However, this does not capture the fact that changes to coal and natural gas-based figures had already started to take place from 1999 onwards, although they are much smaller compared to the changes in the nuclear based variables.

Delaware

As far as Delaware is concerned, coal consumption fell to 0% of total consumption, whereas gas consumption rose to 100% in 2002 and stayed at this level. However, total fuel consumption – the sum of coal and natural gas – drastically fell for 2002 and onwards. Coal- and natural gas-based capacity fell to 0% of total capacity from 2001 onwards, and from 2000 onwards, respectively. Likewise the coal-based generation share fell to 0% from 2002 onwards, whereas the natural-gas based generation share rises to around 68.27% by 2003.

It is rather peculiar that the coal capacity share falls to 0% in 2001 whereas coal consumption and coal based generation shares fall to 0% only in 2002. Likewise, the natural gas capacity share falls to 0% in 2000, whereas the natural gas consumption share rises to 100% in 2000 and natural gas-based generation continues to remain a strong positive component of total generation from 2000 onwards. If one notes that coal and natural gas prices become unavailable from 2002 onwards, then the anomalous natural gas-based consumption and generation post 2002 become quite difficult to explain.

Similar to Connecticut, total capacity and total generation fall drastically in Delaware in the post-restructuring period. If we use the retail access year 2001 as the date to distinguish between the pre- and post-restructuring periods, then average total capacity falls from 2142 MW (1990 – 2000) to just 92 MW (2001 – 2004), whereas average total generation falls from 7,045,198 MWh to only 524,476 MWh.

Both nuclear and natural gas capacity form 0% of capacity, and given that natural gas- and coal-based capacity shares fall to 0% as well, the changes in total capacity and generation seem quite drastic, indicating either that imports became more significant or perhaps that post-restructuring data are not available in the same format as before.

Two striking observations can be concluded in the case of Delaware. First, perhaps the entire analysis may need to be redone with the retail access year defined as the start of the post-restructuring period and second, while it may be tempting to look at the shift from coal- to natural gas-based generation as an indication of a shift in the electricity industry, this information is misleading without considering the data on the respective coal- and natural gas-based capacities, total capacity and total generation.

Maryland

Electricity market restructuring legislation was passed in 1999, whereas full retail access is mentioned to have occurred in 2002. It is in 2002 that fuel consumption – the sum of coal and natural gas consumption – falls to 0 GJ; however as in the case of Connecticut, coal consumption falls to 0% of total fuel consumption, whereas natural gas consumption rises to 100% in 1999. This shift from coal to natural gas consumption in 1999 does not seem significant as total fuel consumption falls from 191,383,453 GJ in 1998 to a mere 3,916 GJ in 1999.

While the drastic change in 2002 boosts the case for using the retail access year as the one that distinguishes between the pre- and post-restructuring period, as in the case of Delaware, the fact that total generation capacity exhibits a drastic change from 2000 onwards cautions against the use of the retail access year as the year to distinguish the two periods. Average total generation capacity falls from 11,603 MW (1990 – 1999) to a mere 205 MW (2000 – 2004). A similar drastic change takes place in total generation for 2000 onwards.

Coal-, natural gas-, and nuclear-based capacity fall to 0% of total capacity for 2000 onwards, which marks a significant change considering the fact that coal-based capacity formed around 42% and nuclear based capacity formed around 16%, respectively, of total capacity in the pre-restructuring period from 1990 – 1998. Coal- and natural gas-based capacity falling to 0% of total capacity 2000 is puzzling because coal- and natural gas-based generation both fall to 0% of total generation in 2001 and in 2002, respectively. This puzzle is similar to that encountered in the case of Delaware.

In the context of Maryland, it can be concluded that the year of legislation will have to be used to distinguish between the pre- and post-restructuring periods despite the fact that some changes only appear after the first year of full retail access. It is also noted that for states with drastic changes like Maryland, the common observation is that total capacity, generation and fuel consumption drastically fall in the post-restructuring period, which indicates that either demand was met through imports or that there has been a difference in the way data have been reported.

Other Restructured Jurisdictions

Drastic drops in total capacity and in total generation are also found in the District of Columbia, Illinois, Maine, Massachusetts, New Jersey, and Rhode Island. Pennsylvania also shows a great reduction in capacity and generation, but not to the same extent as seen in these other jurisdictions.

In the case of New Jersey there seems to be a shift from natural gas-based capacity and generation to coal-based capacity and generation. The natural gas-based capacity share falls to 0% 2000 onwards, but the average coal-based capacity share rises to 27% in the post-restructuring period from about 12% in the pre-restructuring period. This conclusion can be easily derived as the hydro capacity share is 0% for the entire period, whereas the nuclear-based capacity share falls to 0% from 2000 onwards. However, the availability of natural gas prices, and an indication of non-zero natural gas consumption and natural gas-based generation from 2000 – 2004, seems to be a puzzling observation that is at odds with the 0% capacity share values.

The strong conclusion of a shift from natural gas- to coal-based capacity can be made in the case of New Jersey because hydro- and nuclear-based capacities are zero. Such a conclusion cannot be made in the case of Pennsylvania and Montana where the natural gas capacity share also falls to 0% in the post-restructuring period because of positive levels of hydro- and nuclear-based capacities and generation.

As in Connecticut and Delaware, nuclear-based capacity falls to 0% of capacity in the post-restructuring period for Maine, New Jersey, Illinois, Massachusetts, New Hampshire, and Texas, indicating perhaps that restructuring was responsible for this elimination of nuclear-based plants. However, the elimination of nuclear capacity in Oregon, where the restructuring legislation was enacted in1999, took place in 1993 and indicates that elimination of nuclear capacity need not be synonymous with restructuring legislation.

Non-Restructured Jurisdictions

While the preceding analysis focused on drastic changes that took place in jurisdictions that restructured their electricity markets, the following analysis will consider jurisdictions that did not restructure their electricity markets. This is done since it is important to know whether such drastic changes took place only in the restructured jurisdictions, and hence is synonymous with, if not a consequence of, restructuring.

For Washington, the coal-based capacity share falls to 0% from 2000 onwards, whereas the natural gas-based capacity share, which was 0% until 1996, rises to an average capacity share percentage of 1.34% from 1997 – 2004, indicating an apparent shift from coal- to natural gas-based capacity and generation. Nuclear- and hydro-based capacity share data seem to hover around similar percentages through 1990 – 2004. Likewise, there do not seem to be any drastic changes in total generation and total capacity data either, although coal consumption falls to 0% in 2001 and coal prices are not available from 2001 onwards. Thus, although there does not appear to be a drastic reduction in total capacity and generation – in contrast to the case for several jurisdictions that restructured – there does appear to be the same puzzle of having 0% capacity but positive generation. From 1990 – 1996, natural gas-based capacity share is 0%, but natural gas-based generation is positive for the same period.

Idaho exhibits drastic changes in total capacity and generation from 2001 onwards and, like Washington, the natural gas-based capacity share rises from 0% from 1990 – 1993 to an average of 8.28% from 1994 – 2004, although there is no coal-based capacity in Idaho. The information for Washington and Idaho seems to indicate that the addition of natural gas-based capacity is not synonymous with restructuring. Likewise, the cases of Idaho and Vermont indicate that drastic reductions in total capacity are observed in both restructured and non-restructured jurisdictions. The data for Vermont also indicate that the nuclear capacity share falls to 0% for 2001 onwards, thereby substantiating the conclusion that changes in capacity, whether nuclear, coal or natural gas, would have taken place even without the onset of restructuring.

Capacity Utilization

The rest of the information in Tables A5.1.1 to A5.1.5 is quite straightforward, in the sense that it indicates jurisdictions where data on specific variables are not available, where specific variables take on the value of 0% or 100%, or where there are oddities like negative values for some variables such as natural gas-based generation for North Dakota. While the indication of non-availability of data does not require further analysis, the presence of coal-based capacity utilization data being greater than 100% for some jurisdictions for specific years does merit an explanation. Table A5.1.6 indicates the jurisdictions and the years in which utilization exceeding 100% takes place.

Table A5.1.6: Coal Capacity Utilization Exceeding 100%

State	1998	1999	2000	2001	2004
Illinois		123.06%		108.02%	109.21%
Massachusetts	300.80%				
New Jersey			145.93%		
New York		180.89%			
Pennsylvania			113.67%		
Texas				113.44%	
Montana		220.34%			
Mississippi				101.92%	

The situation is similar to that encountered in the context of Connecticut, that is, where capacity is recorded as 0% for a particular year but generation is denoted as a positive percentage either for that year or the subsequent year. In these cases, when coal-based capacity utilization values are computed by using the capacity from the previous year rather than the current year, the problem of having greater than 100% capacity utilization almost disappears. Table A5.1.7 illustrates the newer computations of the coal capacity utilization values in these cases.

Using Illinois as an example in Table A5.1.7, when generation for 1999 is divided by capacity for 1999, the utilization is greater than 100%; however, when the computation is done by using capacity data from 1998, the utilization figure is below 100%. However, for the cases of Mississippi and the 2004 value for Illinois, this computation is of no help. While these two data points will affect the general analysis when the pre- and post- restructuring periods are compared at a very detailed level, these abnormal figures will have no impact for the final analysis that includes comparing the different jurisdictions with respect to different variables to determine the impact of restructuring.

Table A5.1.7: Coal Capacity Utilization using Capacity Figures from the Previous Year

Year	Coal based generating capacity (1)	Coal based electricity generation (2)	Coal based capacity utilization (3) = (2) / [(1)*8760]
Illinois			
1998	15,901	70,306,088	50.47%
1999	6,022	64,918,712	123.06%
			46.61%
2000	5,947	30,522,952	58.59%
2001	3,078	29,124,508	108.02%
			55.91%
2003	1,978	9,390,702	54.20%
2004	1,978	18,923,288	109.21%
			109.21%
Massachusetts			
1997	1,764	12,488,802	80.82%
1998	310	8,168,608	300.80%
			52.86%
Jersey New			
1999	1,728	6,387,952	42.20%
2000	416	5,317,916	145.93%
			35.13%
Pennsylvania			
1999	11,386	85,580,344	85.80%
2000	3,686	36,704,124	113.67%
			36.80%
Texas			
2000	20,477	137,876,672	76.86%
2001	13,313	132,296,608	113.44%
			73.75%
Montana			
1998	2,514	16,507,968	74.96%
1999	828	15,981,559	220.34%
			72.57%
Mississippi			
2000	2,150	13,877,065	73.68%
2001	2,150	19,196,064	101.92%
			101.92%

Another data anomaly that remains unresolved is the coal-based generation percentage for New Jersey for 2004. It is not clear how coal-based generation can be higher than total generation, as shown in Table A5.1.8.

Table A5.1.8: Coal-Based Generation in New Jersey in 2003-2004

New Jersey	Coal based electricity generation (1)	Total electricity generation (2)	(3) = (1) / (2)
2003	1,792,734	1,910,115	93.85%
2004	1,800,845	1,648,908	**109.21%**

Summary

To summarize the findings here, drastic changes observed in jurisdictions that restructured their electricity markets are not unique to them; similar changes are also found in some of the jurisdictions that did not restructure their electricity markets. Based on the selected jurisdictions considered here in more detail, a general pattern cannot be deduced for restructured and non-restructured jurisdictions. For instance, in some of both kinds of jurisdictions, nuclear capacity falls to zero. Likewise, total generation and capacity are observed to have drastically fallen for both types of jurisdictions.

A general observation, such as there having been a shift from coal to natural gas capacity, cannot be made for jurisdictions that restructured given the general decrease in both coal- and natural gas-based capacities for select jurisdictions considered above. Moreover, the shift from coal- to natural gas-based capacity in Washington indicates that such shifts may have occurred anyway without the need of any restructuring legislation or effort.

The shift from natural gas- to coal-based capacity in the case of New Jersey – a jurisdiction that restructured – also points toward the fact that any generalization cannot be made based on the analysis of select jurisdictions. It is for this reason that a general analysis of the entire 51 jurisdictions is conducted rather than just an analysis of those jurisdictions that exhibit some form of a drastic change in specific variables.

Appendix 5.2: Critique of the Wellenius and Adamson (2003) Approach to Determining Counterfactual Electricity Prices for Alberta

A5.2.1 Introduction

Studies that have investigated the impact of electricity market restructuring on electricity prices, reviewed in Section 3.5 (of Chapter 3), were mostly conducted in the US context. As far as the Alberta electricity market is concerned, only Wellenius and Adamson (*W&A*) (2003) calculate counterfactual electricity prices to study the impact of restructuring on electricity prices. As discussed below, the authors identify factors that they believe would have increased costs, and hence electricity prices, under continued regulation. They argue, as have we in earlier chapters, that post-restructuring electricity prices should not be compared with pre-restructuring electricity prices but rather with so called counterfactual electricity prices, that is, electricity prices that would have prevailed in the post-restructuring period assuming continued regulation. To this end, W&A also argue that comparing Alberta electricity prices to those in other jurisdictions is inappropriate as the “regulatory, resource, and investment profile in the two markets cannot be directly compared” (W&A, 2003).

Since this study by W&A (2003), and the follow-up by Wellenius (2004), are the only studies that are in any way comparable to the analysis that is reported in this dissertation, and given that their results contrast with those that we have obtained, it is important to identify exactly what their conclusions are, how they obtained them, whether they are appropriate, and why they appear to differ from those in Chapters 4 and 5 of this dissertation. This is the purpose of this appendix.

A5.2.2 Overview

W&A (2003) claim that electricity prices in Alberta would have increased under continued regulation due to factors such as the lack of significant capacity additions because, while the older generation units had low book costs due to deprecation as these plants were built in the 1970s and 1980s, newer plants had proven significantly more costly to build prior to the onset of restructuring. W&A (2003) indicate that, under the cost-of-service (COS) framework, this tight supply situation along with high natural gas prices, among other factors, would have contributed to an increase in the per-unit costs of generating electricity, and hence consumers would have expected to see an increase in their electricity bills under continued regulation.

In their determination of counterfactual electricity prices, W&A (2003) do not use a regression framework to control for the impact of variables whose roles they highlight, such as natural gas prices and capacity additions. Thus, rather than determining counterfactual prices on the basis of a structural model as has been done in Chapter 4 of this dissertation, their study is couched in a COS framework in which they use certain assumptions to construct the counterfactual electricity prices. In essence they consider four scenarios distinguished in part by, among other criteria, whether future capacity additions would be wholly natural gas-based, or 50% coal-based. Given these scenarios, and on the basis of the energy source-based mix of existing regulated plants, they compute a sum of both the fixed and variable operating costs of electricity generation. That figure is divided by the expected amount of energy that would be consumed in each post-restructuring year to determine counterfactual regulated electricity rates for those years.

On the basis of this exercise W&A (2003) conclude that in three of the four scenarios, regulated rates would have been higher than deregulated prices by 2005, if not sooner. In a follow-up study, Wellenius (2004) updated that work and again concluded that Alberta consumers would not have been better off under continued regulation, and that consumers would be set to reap the benefits of lower prices as a result of restructuring as early as 2004 or 2005. Apart from lower prices W&A (2003) also consider increased generation capacity, increased wind-based capacity and increased efficiency – as measured by heat rates – among other benefits that are indicative of the success of restructuring. However, residential electricity prices in Alberta have never returned to their pre-restructuring levels – let alone being lower than their pre-2001 values – and although inflation has meant that prices have increased everywhere, Edmonton when ranked alongside other Canadian cities on the basis of electricity prices, remains at a similar rank in 2010 as it had been at in 1998 (Hydro Quebec, 2010). With the benefit of hindsight, the conclusions presented in both W&A (2003) and Wellenius (2004) do not seem to be warranted.

The results presented in Chapter 4 of this dissertation indicated that, based on a structural model of electricity prices and controlling for the effects of various factors in the regression framework that is employed, counterfactual electricity prices appear to be lower than the actual electricity prices that were realized in Alberta. Chapter 5 indicated that not only was controlling for the impact of various variables on electricity prices essential but the issue of endogeneity also needed to be addressed to arrive at an appropriate conclusion regarding the impact of electricity market restructuring on electricity prices. Thus, based on a more robust methodology that involved a simulation framework that accounted for the impact of restructuring on variables such as capacity, heat rates and utilization ratios among others, the conclusion obtained in Chapter 4 was robustly supported. Thus, the analysis in Chapters 4 and 5 indicates that electricity prices would have been lower in Alberta under continued regulation. In this context, it is, therefore interesting to recall from Section 3.4, that both Blumsack et al (2008) and Kwoka (2006) note that while studies conducted by the industry and consultants report price savings from restructuring, studies conducted by academics do not find any evidence on the connection between lower electricity prices and electricity market restructuring.

The reason that the conclusions obtained in this dissertation contrast starkly with those found in W&A (2003) may have to do with the differing methodologies that are used. However, it is likely that a significant difference arises from the fact that in their construction of counterfactual electricity prices, W&A (2003) ignore the issue of endogeneity by forecasting electricity prices using cost inputs that already reflect the effect of restructuring. It is precisely this issue that was addressed in Chapter 5 of this dissertation, and as such it would be naïve to employ the post-restructuring cost inputs used by W&A (2003) to determine what prices would have looked like in the absence of restructuring.[1] Since the W&A study is couched in a COS framework that requires information on the various cost inputs for the post-restructuring period, which in general are not publicly available, it is not feasible to conduct a detailed critique of the W&A study that evaluates the assumptions that were used concerning these costs inputs. Rather, we focus on a critical assessment of eight salient points raised by W&A (2003) or by Wellenius (2004), as listed below.

1) Post restructuring, Alberta's market has succeeded in attracting 3,000 MW of new generation investment (Wellenius, 2004).

2) Electricity demand was 16.1% higher in 2002 than in 1999 and prices for natural gas were 40.4% higher. Yet market prices in 2002 were only 2.8% higher than in 1999. Thus, competition worked to create downward pressure on prices (W&A, 2003).

3) In three of the four scenarios analyzed, regulated rates would have been higher than deregulated prices by 2005, if not sooner (W&A, 2003).

4) The $2 billion returned to consumers in Alberta's restructuring process largely offset initial high prices post restructuring (W&A, 2003).

5) Capital costs are computed assuming an 8% rate of return (W&A, 2003).

6) Post restructuring, new capacity is being built through private investment, not at ratepayer risk as under regulation (Wellenius, 2004).

7) Post restructuring, average market heat rates continue to decline, reflecting continued operational improvements (Wellenius, 2004).

8) Post restructuring wind power is especially flourishing (Wellenius, 2004).

[1] While W&A (2003) do modify their cost inputs to account for the four scenarios they consider, these cost inputs remain dependent on a COS framework. For example, the demand variable (peak load) is measured in MW units whereas total load is measured in GWh, and as such contributes to the issue of endogeneity (see discussion in Section 4.2.1.1).

A5.2.3 Analysis of the Claims of W&A (2003) and Wellenius (2004)

A5.2.3.1 Claim 1: Post Restructuring, Alberta's Market has Succeeded in Attracting 3,000 MW of New Generation Investment.

Wellenius (2004) attributes the addition of about 3,000 MW of generation capacity in Alberta to restructuring. While the time period and data sources are not directly mentioned for this claim, W&A (2003) use IPPSA (Independent Power Producers Society of Alberta) and Alberta Energy sources to obtain capacity figures from 1997 – 2003. For this current analysis, it is assumed that Wellenius (2004) is referring to 3000 MW of generation capacity for the 1997 – 2003 time period.

This number appears to be justified by Alberta Electric Industry Annual Statistics, the data source for generation capacity used in this dissertation, as the difference between the 2003 and 1997 generation capacity levels is determined to be 2,986 MW. Moreover, if the changes in generation capacity for seven year periods are computed going back to 1969, as indicated in Table A5.2.1, it becomes clear that the change from 1997 – 2003 is the largest of all those considered since 1969.

Table A5.2.1: Seven Year Capacity Changes from 1969 - 2003

Seven year time period	Capacity change (MW)
1969-1975	1,394
1976-1982	1,780
1983-1989	1,035
1990-1996	1,302
1997-2003	2,986

However, the particular two years that are chosen for this calculation are somewhat arbitrary, and different results can be obtained by computing the difference between different sets of years. For example, Table A5.2.2 indicates that when the difference is computed between average pre- and post- restructuring values, the large increase in generation capacity falls to about 2,300 MW which, while smaller than the 3,000 MW change suggested above, is still a sizeable amount.

Table A5.2.2: Capacity Change between the Pre- and Post-Restructuring Time Periods

Average total capacity (MW)	
1996 - 2000	8,876
2001 - 2005	11,161
Capacity Change	2,285

However, the change in capacity from 1997 – 2003 of 3,000 MW should be compared with what capacity would have been in the same time period in the absence of the implementation of any restructuring initiatives in Alberta. Based on the approach developed in Chapter 5, after matching the 20 restructured jurisdictions for which the relevant data were available with their counterpart non-restructured jurisdictions on the basis of the three composite variables (reflecting capacity/generation, fuel prices and demand), three sets of difference in differences (*d-i-d*) values were obtained for the total capacity variable. These *d-i-d* values were added to the actual total capacity values for Alberta for 2001 – 2003 to obtain three sets of counterfactual capacity figures. This addition was done so as to remove implausible values of capacity figures above 15,000 MW, which left less than 15 corresponding *d-i-d* figures in each of the three sets. Therefore, the remaining *d-i-d* values were combined and treated as if they emanated from a single underlying distribution. This provided enough observations to run Monte Carlo simulations to obtain a distribution of the counterfactual total capacity values in Alberta.

The simulations indicated that 67.87% of the counterfactual total capacity values for 2001 were greater than the observed value of 10,650 MW. Likewise, 67.86% of the counterfactual total capacity values for 2002 and 2003 were greater than the observed values of 11,222 MW and 11,600 MW respectively. These simulation results suggest that under continued regulation, total generation capacity would likely have been higher than the actual values observed for the first three post-restructuring years, and that therefore under continued regulation total capacity would have increased by more than 3000 MW between 1997 and 2003.

A5.2.3.2 Claim 2: Electricity Demand was 16.1% Higher in 2002 than in 1999 and Prices for Natural Gas were 40.4% Higher. Yet Market Prices in 2002 were only 2.8% Higher than in 1999. Thus, Competition Worked to Create Downward Pressure on Prices.

W&A (2003) extract electricity prices (average of monthly power pool prices) and electricity demand (peak load) from the Power Pool of Alberta, and Independent Power Producers Society of Alberta (IPPSA), respectively, whereas they extract the AECO prices for natural gas prices (average of weekday daily spot AECO prices) from Bloomberg.[2] In contrast to their data which pertain to wholesale markets, data used in this dissertation pertain to residential consumers in the retail sector. As already noted in Chapter 4, the electricity and natural gas prices have been extracted from *Electric Power Statistics,* whereas electricity demand figures – proxied by HDD, residential demand, and average real GDP – were collected from *Electric Power Statistics* (EPS) and *The Conference Board of*

[2] While W&A (2003) do not provide detailed information on their data sources, it appears by “AECO prices from Bloomberg” that they are referring to the AECO – C HUB spot prices for natural gas, which is the Alberta gas trading price, available from the Bloomberg website, http://www.bloomberg.com/apps/quote?ticker=NGCAAECO:IND (last accessed, July 2011).

Canada (CBOC). These data are presented in Table A5.2.3 along with electricity prices for Edmonton, specifically the residential average electricity price (excluding taxes) based on 1000 kWh power consumption load (Hydro Quebec, 1993-2010), that are provided for comparison purposes.

Table A5.2.3: Electricity Price, Natural Gas Price and Demand Variables for 1999 and 2002

Year	Hydro Quebec	EPS				CBOC
	Electricity Price (c/kWh)	Electricity Price (c/kWh)	Natural gas price ($/GJ)	HDD	Residential demand (MWh)	Average real GDP ($)
1999	7.51	8.36	2.87	5,020	6,770,915	108,965
2002	11.18	10.86	4.02	5,375	7,989,180	120,507
change	48.87%	29.90%	40.31%	7.08%	17.99%	10.59%

Although the percentage changes from 1999 – 2002 for natural gas prices and residential demand are consistent with those provided in W&A (2003), the percentage changes in both sets of electricity prices are completely different from the 2.8% increase that is indicated by W&A. Given a 40% increase in natural gas prices, electricity prices are shown to increase by between 30% and 50%, depending upon the data source used. Hence, the W&A conclusion that competition has led to a downward pressure on electricity prices does not appear to be supported.

W&A (2003) compare the actual electricity price in 2002 to the price in 1999. However, it is perhaps more important to determine how electricity prices have changed relative to what they would likely have been under continued regulation, that is, how the 30 – 50% increase in electricity prices, observed in Table A5.2.3, compares with how much electricity prices would have changed between 1999 and 2002 under continued regulation. For this purpose, various counterfactual electricity prices for 2002, as determined in Tables 5.36, 5.38, and 5.39 of Chapter 5, and which account for the endogeneity issue discussed previously, are presented in Table A5.2.4.

The average change in electricity prices, assuming continued regulation, is computed to be 4.13%, much less than the observed 30% to 50% increase observed with the restructured market. Moreover, Table A5.2.4 also indicates the percentage of counterfactual prices that are actually below the actual observed electricity price in the post-restructuring period. On average, 93.70% of the counterfactual electricity prices were actually less than the observed electricity prices in 2002. This finding strongly supports the claim that electricity prices would have increased less with continued regulation than under restructuring.

Table A5.2.4: Actual Electricity Price (1999) and Counterfactual Electricity Prices (2002) (c/kWh)

Year	Levels model estimated 1965-2000 Combined d-i-d	Generation/ Capacity composite variable	Fuel price composite variable	Electricity demand Composite variable	Levels model estimated 1965-1997	First differenced model estimated 1966-2000
1999	8.36	8.36	8.36	8.36	8.36	8.36
2002	9.04	8.88	8.73	8.99	7.68	8.91
change	8.13%	6.22%	4.43%	7.54%	-8.13%	6.58%
Average change	4.13%					
% forecast P < actual P	89.74%	91.76%	95.02%	90.71%	97.36%	97.60%
Average % forecast P < actual P	93.70%					

While claiming that post-restructuring electricity prices increased by only 2.8% from 1999 – 2002, W&A (2003) do not appear to expressly mention what they believe this increase would have been under continued regulation. They do provide two counterfactual electricity prices for 2002 in units of $/MWh, however, and when the percentage changes between the 2002 counterfactual electricity prices and the 1999 actual prices are computed in comparable units, the W&A (2003) figures indicate that electricity prices would have increased by less than 2.8% under continued regulation. These percentage changes are shown in Table A5.2.5.

Table A5.2.5: Counterfactual Electricity Price Changes from W&A (2003)

Year	Actual electricity prices ($/MWh)	W&A counterfactual electricity prices ($/MWh)	
		all gas	50% coal
1999	42.74	42.74	42.74
2002	43.93	43.91	42.26
change	2.78%	2.74%	-1.12%

A5.2.3.3 Claim 3: In Three of the Four Scenarios Analyzed, Regulated Rates would have been Higher than Deregulated Prices by 2005, if not Sooner.

W&A (2003) did not have the benefit of hindsight when comparing counterfactual electricity prices to actual electricity prices for 2001 – 2005, so two sets of forward prices were determined in W&A (2003) and updated in Wellenius (2004) for 2003 – 2005 to allow for that comparison. In fact, W&A (2003) expressly provide electricity price figures only for 1999 and 2002. Average annual power pool prices for 2001- 2005 are extracted from one of the Alberta Electric System Operator AESO presentations by Letourneau (2008), in order to determine whether the above W&A conclusion holds in retrospect. Table A5.2.6 includes two sets of forward prices, the two sets of counterfactual electricity prices from W&A (2003) and the actual average annual power pool prices for Alberta from Letourneau (2008). By comparing the counterfactual electricity prices, in Columns (4) and (5) with the forward prices in Columns (2) and (3), W&A (2003) claim that by 2005 the electricity prices under continued regulation, specifically those in Column (4), would be higher than those provided under a restructured market, specifically as in Column (2). However, they do concede that under the scenario where 50% of future capacity expansions are brought forth by coal-based capacity, prices under continued regulation, Column (5), would be lower than those under a restructured market.

Table A5.2.6: Counterfactual, Forward and Actual Electricity Prices

Year (1)	W&A Electricity prices ($/MWh)		W&A counterfactual electricity prices ($/MWh)		AESO actual electricity prices ($/MWh) (6)
	Forward (2)	Forward (3)	all gas (4)	50% coal (5)	
2001	71.29	71.29	45.91	42.40	71.29
2002	43.93	43.93	43.91	42.26	43.93
2003	64.48	64.58	52.16	46.51	62.99
2004	55.68	55.59	53.10	47.20	54.59
2005	54.28	59.55	56.69	49.47	70.36

Note: The updated numbers in Wellenius (2004) are used where applicable. Column (4) gives the base case forward electricity price, whereas Colum (5) gives the forward electricity prices that accounted for the projected market heat rates and forward gas prices. Columns (4) and (5) provide the base case counterfactual regulated electricity prices. Wellenius (2004) also computed two more sets of counterfactual regulated electricity prices, which are not shown, as part of their sensitivity analysis. However, these counterfactual regulated electricity prices do not alter their results except for increasing Column (4) numbers for 2004 and 2005 so that they are slightly higher than the corresponding figures in Columns (2) and (3).

When the counterfactual regulated electricity prices for 2001 – 2005 in Columns (4) and (5) of Table A5.2.6 are compared with the actual electricity prices in Column (6), it is clear that regulated electricity prices would indeed have been below the actual electricity prices that have prevailed in the restructured Alberta electricity market.

A5.2.3.4 Claim 4: The $2 Billion Returned to Consumers in Alberta's Restructuring Process Largely Offset Initial High Prices Post Restructuring.

W&A (2003) do not explicitly mention that their emphasis is on residential consumers, and while their use of Power Pool data rather than retail price data may lead one to conclude that perhaps their focus may be on industrial consumers, it is interesting to observe that they do make an express note on typical residential bills. W&A (2003) state (emphasis added):

> *This paper focuses on the costs and benefits associated with Alberta's restructured electric energy market. It does not explore the costs associated with Alberta's distribution and transmission businesses, as those portions of the industry remain regulated. This is an important distinction, as electric energy costs comprise only a portion of typical <u>residential</u> electricity bills.*

In any event, the entire $2 billion (or $2.2 billion) resulting from the power purchase agreement auctions, does not appear to have been returned to Alberta consumers in 2001. Rather, a $40 / month rebate on residential electricity bills for 2001 was provided (Manning, 2006), so that based on there being 1,125,590 households in 2001,[3] the total amount returned to residential consumers can be computed as $540,283,200 (1,125,590×12×40). Although smaller than $2 billion, this is nevertheless not a trivial amount. However, to put it in context, it is useful to compare this value with the present value of the savings, computed at 2001, that residential consumers might have expected to enjoy from 2001 – 2005 under continued regulation. Table A5.2.7 shows the present values of the savings based on a 5.78% interest rate, which was the interest rate on 10 year long term bonds in 2001. This interest rate was used because it was extracted from the series that was used to determine the cost of capital in Chapter 4.

Six sets of savings figures were calculated as six sets of counterfactual electricity prices were produced. The average present value of savings in Table A5.2.7 is computed to be $362,328,918, which is clearly less than the $540,283,200 received by Alberta consumers in 2001 by roughly $178 million. On a per-month, per-household basis, this implies that under continued regulation, households would have been worse off by $13.17 per month in 2001. However, it may be noted that only 5 years of savings have been computed so far, and that the inclusion of more years may temper or perhaps reverse the conclusion in favour of restructuring.

This does indicate that restructuring may have been beneficial if only because of the one-time payout in 2001; a benefit that arises from institutional change in the electricity market rather than from competitive forces generated by

[3] This figure was extracted from CANSIM series V13874904, entitled "Total Shelter; Estimated Number of Households Reporting", which is obtained from the Survey of Household Spending.

restructuring. Moreover, under restructuring, W&A (2003) mention that the $40 per month rebates largely offset the higher electricity bills in 2001. This would seem to suggest that consumers were cushioned but their welfare did not generally increase. Now if consumers were merely cushioned in 2001, then it may be noted that under continued regulation, instead of being merely cushioned, consumers would have been better off by $57,681,237, which roughly translates to $22 extra per taxpayer in 2001.[4]

[4] This number is obtained by taking the average savings in 2001 of $57,681,237 (from Table A5.2.7), and distributing them over twelve months. These monthly figures were multiplied by the monthly population given by CANSIM series V2064510 to obtain monthly benefits to consumers under continued regulation.

Table A5.2.7: PV of Savings to Residential Consumers from 2001 – 2005, Computed at 2001

Year (1)	Actual electricity prices (c/kWh) (2)	Counterfactual Electricity prices (mean values c/kWh)						Residential Disposal (MWh) (9)
		Levels model estimated 1965-2000 Combined d-i-ds (3)	Generation/ capacity composite variable (4)	Fuel price composite variable (5)	Electricity demand Composite variable (6)	Levels model estimated 1965-1997 (7)	First differenced model estimated 1966-2000 (8)	
2001	9.16	8.66	8.6763	8.5907	8.7300	7.1723	8.6446	7,722,580
2002	10.86	9.04	8.8774	8.7280	8.9948	7.68	8.9094	7,989,180
2003	10.75	9.71	9.8036	9.5015	9.6821	8.4582	9.458	7,539,844
2004	10.23	9.48	9.4040	9.3572	9.5978	8.342	9.479	7,650,109
2005	10.25	10.64	10.4898	10.6196	10.8403	9.5348	10.1596	7,819,372
Expenditure (price × residential disposal) $								
2001	707,388,328	669,130,667	670,034,209	663,423,680	674,181,234	553,886,605	667,586,151	
2002	867,624,948	722,469,537	709,231,465	697,295,630	718,610,763	613,569,024	711,788,003	
2003	810,533,230	732,329,968	739,176,146	716,398,278	730,015,236	637,735,085	713,118,446	
2004	782,606,151	725,521,037	719,416,250	715,835,999	734,242,162	638,172,093	725,153,832	
2005	801,485,630	832,223,581	820,236,484	830,386,029	847,643,383	745,561,481	794,416,918	
PV savings (at 5.78%)								
2001		38,257,661	37,354,119	43,964,648	33,207,094	153,501,723	39,802,177	
2002		137,223,872	149,738,592	161,022,233	140,871,796	240,173,874	147,321,748	
2003		69,890,435	63,771,990	84,128,623	71,959,116	154,430,099	87,059,817	
2004		48,229,436	53,387,180	56,412,023	40,861,229	122,027,840	48,539,676	
2005		-24,550,518	-14,976,378	-23,082,858	-36,866,373	44,666,830	5,645,807	
total		368,280,897	267,705,707	316,737,682	254,179,888	605,263,291	321,774,142	
Average savings*	362,328,918							

*Savings are computed as the differences between each of Columns (3) through (8) with Column (2).

A5.2.3.5 Claim 5: Capital Costs are Computed Assuming an 8% Rate of Return

W&A (2003) compute the Weighted Average Cost of Capital (WACC) for 2001 – 2005 simply by assuming a figure of 8%. However, the WACC computed in this dissertation is based on an extensive review of sources such as FP Bonds as well as the financial statements of the three principal utilities: EPCOR, TransAlta and ATCO. This WACC is based on a CAPM approach, and is computed using data for D/E ratios, yield to maturity on bonds, betas and risk premia for the three principal utilities. The WACC computations indicate that for Alberta the cost of capital in the post restructuring period 2001 – 2005 declined to 5.24% from the 7.42% that prevailed in the immediate pre-restructuring period 1996 – 2000. Thus, using a WACC value of 8% for 2001 – 2005 might be misleading.

This may be an important factor, since higher costs of capital under restructuring would, to some extent, have explained higher electricity prices observed by consumers; however, if the cost of capital actually did decline then part of the justification for higher electricity prices observed by consumers post restructuring would not hold. Moreover, in the context of the PV exercise in Section A5.2.3.4, a lower cost of capital of 5.24%, compared to the 5.78% used would also serve to increase the savings from continued regulation.

A5.2.3.6 Claim 6: Post Restructuring, New Capacity is being Built through Private Investment, not at Ratepayer Risk as under Regulation.

Although ratepayers may be exempt from the risks associated with paying for unwanted capacity that would arise under regulation, now they may have to face problems associated with insufficient capacity addition (potential blackouts or brownouts), which is perhaps why a capacity market has been introduced in some jurisdictions as part of restructuring initiatives. Absent such capacity markets, the passing of risks of capacity addition from ratepayers to private investors may simply seem to be an exchange of this risk for the insufficient capacity risk.

Moreover, the shift of risk from ratepayers to private investors should not be an end but a means to the end of achieving lower electricity prices. Given the computations of counterfactual electricity prices, it appears clear that electricity prices have increased in the post-restructuring period, which would suggest that any shift of risk from ratepayers to private investors plays little role in assessing the costs and benefits of restructuring.

A5.2.3.7 Claim 7: Post Restructuring, Average Market Heat Rates Continue to Decline, Reflecting Continued Operational Improvements.

W&A (2003) indicate that the average market heat rate fell from 13.7 GJ/MWh in 2001 to 11.3 GJ/MWh in 2002, a decrease of 2.4 GJ/MWh. Based on this reduction, Wellenius (2004) makes the claim that restructuring has contributed toward operational improvements. This market heat rate is computed by dividing the price of electricity in units of $/MWh by the price of natural gas in units of $/GJ. However, it is clear from this definition that coal prices are not considered in determination of the market heat rate, which brings into question the values for the 'market' heat rate. An alternative set of heat rates is computed in this dissertation for both coal and gas plants separately by dividing the heat content of the respective fuel used in generating electricity in units of GJ by the amount of electricity generated in units of MWh. This computation, as opposed to being based on market prices, is based on the technical definition of efficiency, and as such provides more detail on the respective thermal efficiencies of the two types of power plants.

Table A5.2.8 provides these heat rates in columns (2) and (3). The values for the heat rates for 2001 and 2002 turn out to be less than the 13.7 and 11.3 GJ/MWh figures of W&A (2003), although the change from 2001 – 2002 is less pronounced than the 2.4 GJ/MWh decline that they obtain. Specifically, the natural gas-based heat rate declines by 1.57 GJ/MWh, whereas the coal-based heat rate actually increases by 0.14 GJ/MWh.

Table A5.2.8: Coal and Natural Gas Based Annual Heat Rate Changes 1990-2005

Year (1)	Gas based heat rate (GJ /MWh) (2)	Coal based heat rate (GJ/MWh) (3)	Change in gas based heat rate (4)	Change in coal based heat rate (5)
1990	12.64	11.20	0.66	0.06
1991	12.97	11.92	0.33	0.72
1992	6.08	10.46	-6.88	-1.46
1993	5.75	11.27	-0.34	0.81
1994	6.17	11.31	0.42	0.03
1995	6.51	11.23	0.34	-0.07
1996	5.63	11.27	-0.88	0.04
1997	6.16	11.22	0.54	-0.06
1998	6.38	11.38	0.22	0.17
1999	5.74	11.32	-0.64	-0.06
2000	7.40	11.14	1.66	-0.19
2001	7.07	11.07	-0.33	-0.07
2002	5.50	11.21	-1.57	0.14
2003	5.07	11.13	-0.43	-0.08
2004	5.62	11.07	0.55	-0.06
2005	6.85	11.55	1.23	0.49

Notwithstanding the difference between market and plant heat rates, based on these figures it seems that the improvement in heat rates, as indicated by the larger magnitude of decline in their values, appears to have been overestimated in W&A (2003). Moreover, based on Table A5.2.8, it appears that restructuring is not essential for a marked improvement in heat rates, and hence efficiency, as indicated by the huge declines in both natural gas- and coal-based heat rates from 1991 – 1992, that is, declines of 6.88 and 1.46 GJ/MWh, respectively.

A5.2.3.8 Claim 8: Post Restructuring, Wind Power is Especially Flourishing.

Wellenius (2004) while mentioning the increase in wind power generation in post-restructuring Alberta, does not provide exact numbers as to that increase. Averages based on the data on wind power capacity from EPS statistics are presented in Table A5.2.9. The computations there indicate that when the 5 years pre- and post-restructuring are compared, the increase in wind power generation turns out to be around 153 MW.

Table A5.2.9: Alberta Wind Capacity (MW)

Time period	wind capacity (MW)
1996-2000	32.8
2001-2005	185.4
change	152.6

However, as with total generation capacity and electricity prices, these figures should ideally be viewed in the context of the counterfactual values of wind power capacity. In the absence of such values, Table A5.2.10 provides the existing capacity and capacity under construction for both restructured and non-restructured jurisdictions in the US for 2010. These figures can be compared to ascertain whether restructuring is an essential pre-requisite for wind power capacity addition to the electricity market.

The information in Table A5.2.10 indicates that while total wind power capacity for restructured jurisdictions is higher than for non-restructured jurisdictions, the converse holds true for wind power capacity under construction. Moreover, on closer inspection it becomes apparent that the high Texas figures are driving the result in favour of restructured jurisdictions. Once Texas is removed from the picture, the existing capacity figures for restructured jurisdictions become lower than the capacity figures for non-restructured jurisdictions. Likewise, capacity under construction figures for restructured jurisdictions also decrease in this case, and become much lower than for non-restructured jurisdictions. In short, if not an impediment, at the very least restructuring does not seem to be a necessary pre-requisite for the increases in wind power capacity.

Table A5.2.10: Wind Power Capacity (MW)

Non Restructured State	Existing Capacity	Under Construction	Restructured State	Existing Capacity	Under Construction
Iowa	3,670	0	Texas	9,727	350
Washington	1,964	735	California	2,739	443
Minnesota	1,818	677	Oregon	2,095	201
Colorado	1,248	552	Illinois	1,848	587
Indiana	1,238	99	New York	1,274	95
North Dakota	1,222	202	Oklahoma	1,130	709
Wyoming	1,101	311	Pennsylvania	748	38
Kansas	1,026	0	New Mexico	597	102
Missouri	457	0	Montana	386	0
Wisconsin	449	182	Maine	200	126
West Virginia	431	0	Michigan	143	20
South Dakota	412	210	Arizona	63	65
Utah	223	102	New Hampshire	26	0
Idaho	164	308	Massachusetts	17	15
Nebraska	153	264	Ohio	10	304
Hawaii	63	30	New Jersey	8	0
Tennessee	29	0	Rhode Island	2	0
Alaska	9	0	Delaware	2	0
Vermont	6	40	Arkansas	0	0
Alabama	0	0	Connecticut	0	0
Florida	0	0	Maryland	0	120
Georgia	0	0	Nevada	0	0
Kentucky	0	0	Virginia	0	38
Louisiana	0	0			
Mississippi	0	0			
North Carolina	0	0			
South Carolina	0	0			
Total	15,683	3,712	**Total**	21,015	3,213
			Total excluding Texas	11,288	2,863

A5.2.4 Summary

The stark difference between the conclusions reached in this dissertation and those of the W&A (2003) study, the only other one to have computed counterfactual electricity prices for Alberta, warrants a closer inspection of the W&A (2003) study. It is noted that while part of the difference in results might be explained by differing methodologies, in that W&A (2003) does not employ a regression-based structural model for electricity prices, another significant difference between the two studies is that the W&A (2003) study ignores the issue of endogeneity by forecasting electricity prices using cost inputs that already capture the effect of restructuring. However, the W&A study is couched in a COS framework that requires information on the various cost inputs for the post-restructuring period, which are in general not publicly available, so that a detailed critique of the W&A study is not feasible.

Nonetheless, a critical assessment of eight salient points raised by W&A (2003) and Wellenius (2004) is provided. It was found that because W&A ignored endogeneity, their results on the expansion of both total capacity and wind capacity in the post-restructuring period were exaggerated. Moreover, although they mention the residential electricity sector, rather than retail electricity prices they appear to focus on Power Pool prices. Their assumptions concerning heat rates and the cost of capital rate also appear questionable, and with the benefit of hindsight their claim of restructuring leading to lower electricity prices is also rejected. In terms of the eight main claims that they make, only the reference to the benefits achieved by consumers in 2001 due to the $40/ month rebate (discussed in Section A5.2.3.4) may work to support their claims of the merit of restructuring. Yet, even that series of payments has to be considered as a one off event which, no matter how beneficial to consumers, does not justify the higher electricity prices paid by consumers in the post-restructuring period. In short, it is argued on the basis of the methodology developed and applied in Chapter 5, that because W&A (2003) ignore the issue of endogeneity, it would be misleading to use their framework to construct counterfactual electricity prices, and to rely on the findings that they obtain.

Chapter 6: Carbon Dioxide (CO2) Emissions and Electricity Market Restructuring

6.1 Introduction

Since the electricity power sector is a major consumer of fossil fuels, it is also a major contributor to air pollution in terms of Carbon Dioxide (CO2), Sulphur Dioxide (SO2) and Nitrous Oxide (NOX) emissions (Burtraw et al., 2001). In fact, the electricity sector has been identified as the largest source of toxic emissions in the US and Canada (Cohen, 2006). In contrast to NOX and SO2 emissions that are viewed as having predominately local effects, CO2 emissions impact globally (Friedl and Getzner, 2003:134), and CO2 emissions have come to be regarded as one of the main sources of global warming.

According to Thierer (1997), one of the general benefits of electricity market deregulation includes a cleaner environment, as consumers – at least to the extent that they are concerned with such matters – would expect utilities to generate electricity by employing the least environmentally detrimental methods. By virtue of the choice available to consumers in a restructured environment, failure of a particular electricity utility to do so could result in electricity consumers moving to one that does. According to this view, competition would therefore contribute toward innovative ways of minimizing environmental damage from pollution. Electricity market restructuring might therefore be expected to reduce carbon emissions from the power sector.

Of course, it could also be argued that carbon emissions in the electricity sector are more likely to be lower in a regulated framework, provided that the regulator is convinced that this is a worthwhile social objective and is allowed or required to take this into account in rate setting. Through the regulation process, incentives could be provided to induce firms to generate electricity in such a way that CO2 emissions are reduced. In economies like Alberta, which have abundant supplies of thermal coal, such a policy might be expected to result in increased electricity prices, which could put Alberta industry at a competitive disadvantage. On this basis it might be expected that with electricity market restructuring, the incentive for firms is to produce electricity as cheaply as possible, and in view of Alberta's relatively abundant and cheap coal supplies, this could make it less likely that carbon emission reductions will occur with restructuring.

The focus of this chapter is on evaluating which of these two views is more applicable to Alberta. Specifically, the issue that is addressed is the determination of the extent to which carbon emission reductions have occurred or are likely to occur as a result of electricity market restructuring in Alberta. Of course, to the extent that there is a general increase in concern about greenhouse gas (GHG) emissions, any observed reduction in CO2 emissions subsequent to restructuring in Alberta cannot be automatically attributed to the effects of restructuring itself. Rather, it is necessary to determine what might have been expected to occur had restructuring not taken place, and then assess whether has actually been observed involves less than this amount of CO2 emissions. Thus, the methodology that is used has similar features to the methodology used to examine whether electricity prices for residential consumers decreased as a result of electricity market restructuring, as considered in previous chapters.

The motivation for focusing on this issue is threefold. First, to make informed decisions on climate change mitigation it is necessary to identify the determinants of CO2 emissions, and ideally to model their effects. As noted by Quadrelli and Peterson (2007), since CO2 emissions have grown at their highest rates in recent years, understanding the drivers of emission is essential in the process of climate change mitigation. Second, modelling of CO2 emissions has predominantly been done in an Environmental Kuznets Curve framework and on the basis of simulation models, as explained in Section 6.3. This paper attempts to fill the gap in the literature by formulating an industry-specific structural model as opposed to the conventional macroeconomic framework. The disproportionately large role of the electricity sector in contributing to CO2 emissions suggests that this is an important industry on which to focus. Third, a reduction in carbon emissions is sometimes included among the arguments advanced by proponents of electricity market restructuring, so it is important to determine if there is evidence that would support this claim.

The outline of the remainder of this chapter is as follows. After considering some aspects of electricity sector CO2 emissions in the following section, Section 6.3 provides a brief review of relevant literature, while the possible ways in which electricity market restructuring might affect carbon and greenhouse gas (GHG) emissions are examined in Section 6.4. Section 6.5 focuses on identifying the determinants of carbon emissions to be used in a structural model in the context of the electricity market. Such a model is developed in Section 6.6, while data are described in Section 6.7. Estimation and the results obtained from several different model formulations are reported in Section 6.8. These include estimation for the entire period using a dummy variable to indicate the post-restructuring period, as well as the type of counterfactual analysis undertaken in Chapters 4 and 5 in the context of models of the electricity price. Section 6.9 contains a brief summary and conclusions.

6.2 Emissions and the Electricity Sector

In 2004, generation of electricity and heat was responsible for 40% of total world GHG emissions, compared to 26% in 1971 (Quadrelli and Peterson, 2007:5944).[1] Given that energy use represents 80% of emissions, and based on Annex I countries – which include Canada – where 95% of energy-related

[1] While Quadrelli and Peterson (2007) do not define heat, since they are analyzing data from the International energy Agency IEA, given that the IEA website glossary indicates that electricity generation can be obtained from combined heat and power plants, it seems reasonable to assume that 'heat' here is referring to that produced by a combined heat and power plant.

emissions consist of CO_2, it can be concluded that CO_2 comprises just under 80% of global green house gas GHG emissions (Quadrelli and Peterson, 2007).

As far as Alberta is concerned, 39% of total Canadian GHG emissions, and 40% of Canadian CO_2 emissions originated in Alberta in 2005 (Alberta Environment, 2007). Within Alberta, 95% of GHGs were in the form of CO_2 emissions, and power plants were responsible for 47% of these CO_2 emissions. From 1990 – 2004, Alberta GHGs have increased by 40%, the third highest increase in provincial GHG emissions after Saskatchewan and New Brunswick, although emission intensity – kt of CO_2 per million 1997 \$ GDP – has declined by 16% from 1990 – 2004 (Alberta Environment, 2007).

While these statistics indicate the significant contribution of the electricity market sector to carbon emissions in general, it is important to also consider the various methods of electricity generation that are used when considering carbon emissions. In 2004, coal supplied 39% of world wide electricity and heat generation, and from 2003 – 2004 coal use alone was responsible for about 60% of the global increase in emissions (Quadrelli and Peterson, 2007). As far as Canada is concerned, 20% of electricity is generated from high-carbon sources such as coal, natural gas and oil, and this generation accounts for about 17% of greenhouse gas emissions (Cohen, 2006). In the specific case of Alberta, over 85% of coal mined in Alberta is used for electricity generation,[2] and coal-based generation contributes the largest proportion of GHG emissions in Alberta. Between 1993 and 2002, Alberta had the highest level of provincial GHG emissions in Canada due to its large petroleum industry and a high proportion of coal-based electricity generation (Hanus, 2005). In fact, in Alberta, since coal is not suitable as an export commodity, it is the preferred fuel choice in electricity generation (Cohen, 2006). Figure 6.1 highlights the trend in GHG emissions from the electricity sectors in Alberta, Ontario, Saskatchewan and the Atlantic Provinces. Other provinces have very low levels of GHG emissions and hence are not included in this figure.

Figure 6.1 presents GHG emissions for Canada as a whole and for Canadian provinces from the Electricity and Heat Sector, measured in units of kt CO_2 equivalents (CO_2e). According to the Glossary of Climate Change Terms at US Environmental Protection Agency EPA, CO_2e is 'a metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential (GWP). The carbon dioxide equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP. Here GWP is defined as 'the cumulative radiative forcing effects of a gas over a specified time horizon resulting from the emission of a unit mass of gas relative to a reference gas' (US EPA, 2011).

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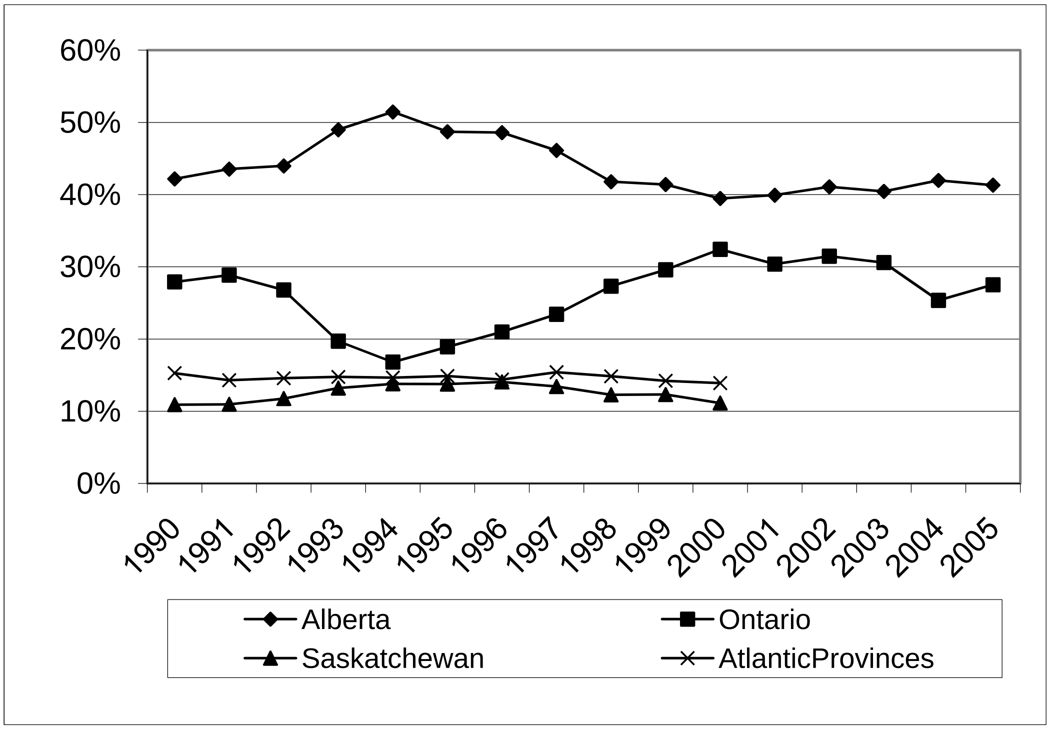
[2] Bato Engineering (2006), Coal Mining, http://www.bato.ca/coalmining.htm (last accessed: July 2011).

Figure 6.1: GHG Emissions (kt CO2 Equivalent) from Electricity and Heat Generation in Various Canadian Provinces as a Percentage of GHG Emissions from Electricity and Heat Generation in Canada



Source: Annex 11: Provincial/Territorial Greenhouse Gas Emission Tables, 1990-2005 and Annex 8: Canada's Greenhouse Gas Emission Tables, 1990–2005; National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada (Environment Canada)

Based on this information, it can be concluded that carbon emissions are a major component of GHG emissions, and that coal-based electricity generation is a major source of these emissions. This has a bearing on electricity market restructuring efforts to the extent that restructuring might be responsible for replacing coal-based electricity generation with green power (wind, solar) and natural gas-based electricity generation. While, it is clear that green power reduces carbon emissions, natural gas-based electricity generation curbs carbon emissions relative to coal-based electricity generation. Among fossil fuels, natural gas has the lowest carbon intensity whereas coal has the highest, which implies that coal-based electricity generation yields the highest output rate of CO2 / kWh (DOE – US, 2000). In fact, compared to natural gas, coal is as much as twice as emission-intensive (depending on the type of coal) due to its heavy carbon content per unit of energy released (Quadrelli and Peterson, 2007).

However, as explained in previous chapters, the influx of natural gas-based electricity generation in Alberta, while associated with restructuring efforts, may not be a specific outcome of restructuring legislation. In fact, one reason underlying the increase in natural gas-based generation may be the reduced costs associated with environmental mitigation technology requirements for natural gas combustion relative to coal combustion (Hanus, 2005). Moreover, factors other than legislation affect the choice of the generation mix. For instance, with rising natural gas and oil prices, coal as the relatively cheaper fuel alternative is substituted to meet energy demand (Quadrelli and Peterson, 2007). Of course, the decline in natural gas prices associated with recent exploitation of shale gas deposits may offset this effect.

The role of restructuring in curbing carbon emissions can be studied by controlling for other variables, such as fuel prices, in the framework of a structural model, so as to not only determine the impact of restructuring on carbon emissions but also to identify the key determinants of carbon emissions that seem to impact GHG emissions and hence climate change. This framework may also be extended to other types of emissions, which may be important since according to Cohen (2006), Alberta has the highest SO2 and NOX emissions in Canada. The determinants of carbon emissions to be included in a structural model can be identified through a review of select policy studies. Before undertaking this review, it is useful to examine the way that GHG and carbon emissions have been studied in the economic literature.

6.3 Literature Review

Many economic studies that deal with carbon or GHG emissions do so within a macroeconomic framework that attempts to relate GHG emissions to GDP growth. There is also a strand of studies that model carbon or GHG emissions on the basis of simulation models. According to Pomorski (2006), most empirical research studying the impact of restructuring on pollutant emissions in the US has been based on large scale simulation models. One such simulation model, called the Electricity Market Simulation Model' (EMM), has been used by the Energy Information Administration for its 1996 *Annual Energy Outlook* to test the emission impacts of electricity market restructuring in the US, specifically Order 888 of the Federal Energy Regulatory Commission (FERC).[3] The United States Department of Energy EIA (1996) study concludes that the emission impact of restructuring through Order 888 would depend more on the overall change in electricity demand than on open access in the electricity market.

Pomorski (2006) also refers to the Haiku electricity market simulation model that tests for the impact of restructuring under different emission regulations in the US. The Haiku model used by Burtraw et al. (2002) is briefly mentioned in Section 6.4.1. In the Canadian context, the 'Canadian Integrated Modelling System' (CIMS) developed by the Energy and Materials Research Group at Simon Fraser University has been used to for over a decade to assess the impact of emission policies on GHG emissions in Canada and other countries

[3] According to FERC (2010), Order 888 concerns 'Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities'.

(Jaccard et al., 2006). An example of the application of the CIMS model to simulate the effect of the Canadian government's 2006-2007 GHG policies is in Jaccard and Rivers (2007), which states that 2006-2007 Canadian GHG policies would not be effective in meeting stated emission targets for 2020 and 2050. Another simulation-based approach to studying CO2 emissions, based on spatial econometrics, simply models CO2 emissions as a function of production (see, for example, Mizobuchi and Kakamu, 2007).

There is also literature that is based on partial and general equilibrium models that attempts to model GHG emissions. Amundsen and Tjotta (1999), who use a partial equilibrium model to evaluate the integration of the Nordic power system, indicate that post-integration hydro power is expected to offset gas based generation, leading to a reduction in carbon emissions (Pomorski, 2006). Leach (2009), on the other hand, uses a general equilibrium model, that includes GHG emissions, to determine the welfare implications of climate change policy. Finally, there is also a strand of literature that that investigates the relationship between residential development – that is, residential energy use, new construction and transportation – and GHG emissions (Fruits, 2008).

The simulation-based studies are used by government institutions like the EIA for the purposes of determining energy outlook scenarios. The modeling used in these simulation-based studies is quite broad, and thus beyond the scope of a narrower study, such as is conducted here, that focuses specifically on carbon emissions in the electricity market. Moreover, to the extent that the simulation models contain proprietary information, it is not clear how such studies can be replicated using a regression-based framework. Likewise, the studies based on partial and general equilibrium models, while having implications for GHG emissions, are not particularly useful for the purposes of directly modelling carbon emissions in the electricity market. In addition, the studies reviewed by Fruits (2008), which focus on emissions from the residential sector, also do not allow for modelling carbon emissions specifically from the electricity power sector. This leaves the studies of GHG emissions that are conducted in a macroeconomic framework to be reviewed in more detail, since they are more relevant for a regression-based framework than are the simulation or partial/general equilibrium studies.

The studies that model carbon or GHG emissions in a macroeconomic framework include, for instance, Hamilton and Turton (2002), who use a decomposition formula to identify the effect of changes in economic structure, new technologies and changes in energy consumption on GHG emission growth in OECD countries from 1982 to 1997. Specifically, they show that emission growth increases in response to per-capita GDP growth, population growth, and increases in the energy required for final energy consumption. Emission growth falls in response to a declining share of fossil fuels and falling energy intensity.[4]

[4] Energy intensity is measured as total final energy consumption per unit of GDP.

Likewise, Selden et al (1999) use decomposition analysis to analyze various pollutant emissions from 1970 to 1990. Among other things, they conclude that reductions in energy intensity contributed more towards emission reduction than did the composition change in emissions due to the higher differential growth rates in the services sector as compared to the manufacturing sector. Since the focus of their study is on analyzing the trends in pollutant emissions through a decomposition analysis in a macroeconomic framework, it is not suitable for examining the determinants of GHG emissions, except perhaps for a brief mention of the contributions of residential and firm electricity usage to substantial emissions of sulphur oxides (SOx).[5]

While Hamilton and Turton (2002) and Selden *et al* (1999) study GHG emissions generally, Friedl and Getzner (2003) focus on carbon emissions. Specifically, they test the Environmental Kuznets Curve relationship – generally defined as the inverted U-shaped relationship between per-capita income and indicators of environmental degradation (Stern, 2003) – in the context of the relationship between economic development and carbon emissions for a small open economy. Explanatory variables in their model include GDP per capita, temperature, the share of imports in GDP and the share of the service sector in GDP. As far as the dependent variable is concerned, carbon emissions can be modelled as emissions per capita, emissions per unit of GDP, ambient levels of pollution (concentration levels), or total emissions. While, in cross sectional studies, emissions per-capita are used, Friedl and Getzner (2003) use total emissions since the Kyoto Protocol targets annual GHG emission levels. The choice of total emissions over other variables such as emission per output or emission per capita, better captures the decline in carbon emissions, as total emissions can increase even when emissions per unit of output or emissions per capita fall. Studying carbon emissions in terms of total emissions also makes sense as carbon emissions have a global impact whereas concentration levels are more suitable for the study of local pollutants.

Quadrelli and Peterson (2007) narrow down the focus even further by analyzing the trends as well as the drivers of carbon emissions, specifically from fuel combustion. They identify socio-economic indicators, economic sectors and types of fuel as important factors in analyzing CO2 emissions, and conclude that energy efficiency improvements and carbon intensity reduction in the electricity generation sector can significantly decrease CO2 emissions and hence mitigate climate change. However, carbon emissions are not explicitly modelled. As with the other studies, Quadrelli and Peterson take a macroeconomic approach to studying carbon emissions.

Neumayer (2004) examines the effect of climate, renewable energy and transportation on carbon emissions. This paper mentions a number of studies that have analyzed the determinants of carbon emissions. Like Friedl and Getzner

[5] SOx refers to any one or more of the following: sulphur monoxide, dioxide, trioxide, higher and or lower sulphur oxides.

(2003), most of these studies, outlined below, focus on the Environmental Kuznets Curve framework and study CO2 emissions as a function of per capita income.

Grossman and Krueger (1995) examine the relationships between per-capita income and four environmental indicators in an Environmental Kuznets Curve framework, and confirm an inverted U relationship between economic growth and environment quality. Galeotti and Lanza (1999) use a panel data model for 110 countries to estimate the relationship between CO2 emissions and GDP, and conclude that the empirical relationship between carbon dioxide and income is well described by non-linear Gamma and Weibull specifications as opposed to more commonly used linear and log-linear specifications. Schmalensee et al. (1998) use national-level panel data for the 1950-1990 period to study carbon dioxide emissions from the combustion of fossil fuels. Using a model that employs a flexible form for income effects, along with fixed time and country effects, and handling forecast uncertainty explicitly, they find clear evidence of an "inverse U" relation between carbon dioxide emissions per capita and per-capita income.

Shafik (1994) provides an econometric analysis of the relationship between economic development and environmental quality for a large sample of countries over time. The results indicate that some environmental indicators improve with rising incomes (water and sanitation), others worsen and then improve (particulates and sulfur oxides), while others worsen steadily (dissolved oxygen in rivers, municipal solid wastes and carbon emissions). Growth tends to be associated with environmental improvements where there are generalized local costs and substantial benefits. But where the costs of environmental degradation are borne by others (by the poor or by other countries), there are few incentives to alter damaging behavior. Given the global impact of carbon emissions, it is not surprising to note the worsening of the indicator that captures carbon emissions.

Heil and Selden (2001) explore appropriate econometric specifications of the relationship between international trade and pollution using data on carbon emissions across 132 countries from 1950 to 1992 and conclude that increased trade intensity raises carbon emissions in lower income countries and lowers carbon emissions in upper income countries. Likewise, Holtz- Eakin and Selden (1995) use a global panel data set to examine the relationship between economic development and carbon dioxide emissions. Their results suggest that, despite a diminishing Marginal Propensity to Emit (MPE) carbon dioxide as GDP per capita rises, emissions growth will continue, as output and population will grow most rapidly in lower-income nations with high MPEs.

Ravallion *et al* (2000) determine that higher income inequality, both between and within countries, is associated with lower carbon emissions. Their study also confirms that economic growth is generally accompanied by higher emissions. Both these findings suggest that trade-offs exist between climate control (on the one hand) and both social equity and economic growth (on the other); however, the study also suggests that economic growth improves the trade off with equity, and lower inequality improves the trade off with growth.

The studies reviewed above have been conducted in a macroeconomic framework with an emphasis on the Environmental Kuznets curve or on the relationship between economic growth and environment quality. While studies like Quadrelli and Peterson (2007) and Schmalensee *et al* (1998) are narrower in focus, in that they deal explicitly with carbon emissions through fuel combustion, none of the current literature looks at the electricity market and its carbon emissions. Moreover, given the macroeconomic framework used even in the more narrowly focused studies, it is difficult to draw out the determinants of carbon emissions in the specific context of the electricity market.

The only study that appears to be directly relevant in the context of modelling carbon emissions in the electricity market, and therefore for investigating the impact of restructuring on carbon emissions, is Pomorski (2006). In this study, detailed plant level data is used to model the emission rate, defined as CO2 emissions divided by generation, as a function of, among other variables, capacity, generation, the heat rate, fuel costs, and an array of dummy variables capturing plant characteristics and the regulation status of plants. However, such a study requires the use of a detailed plant-level data set which is not publicly available for Alberta. Using data for 2002-2006, Pomorski (2006) does find a statistically significant negative impact of restructuring on carbon emissions. However, the issue with this paper is that if fails to account for endogeneity of the explanatory variables and uses fuel costs in output units, that is, in $/MWh, the problems with which were detailed in Section 4.2.1.1 of Chapter 4.

Notwithstanding Pomorski (2006), the following section is concerned with identifying the various channels through which restructuring may impact carbon emissions, while Section 6.5 deals with pinpointing the determinants of carbon emissions that are suitable for use in a structural model in the context of the electricity market.

6.4 How Can Electricity Market Restructuring Impact Carbon and GHG Emissions?

According to Burtraw et al. (2001), changes in electricity market regulation or restructuring may affect the environment either positively or negatively depending on the design of the incentives for complying with environment regulations. This suggests that any effect of restructuring on lowering GHG, and hence carbon emissions, really depends on the type of restructuring that is implemented. This also raises the question of whether legislation in the absence of electricity market restructuring can achieve a similar effect in reducing carbon emissions.

The following review of select policy studies indicates how restructuring can affect GHG and carbon emissions through its impact on the generation mix, plant efficiency, electricity prices, demand management programs and extent of green power generation. This review not only helps in identifying the direction of impact of restructuring on various electricity market variables but also helps in determining the variables to be used in the structural model of the determinants of carbon emissions.

6.4.1 Generation Mix

To the extent that the electricity market is a major contributor of CO2 emissions through coal-based generation, any restructuring initiative that leads to a substitution away from coal-based generation has the potential to reduce carbon emissions (Borbely and Kreider, 2001). In fact, even when the total generation of electricity increases, the output rate – emissions / kWh of electricity generated – can be improved if there a relative shift from coal-based to natural gas-based generation or if there is a reduction in the emission rate from coal-based generation, perhaps due to cleaner coal or improved technology.[6] In these circumstances, the increase in aggregate emissions due to increased generation capacity is tempered relative to the case in which there is no change in the generation mix.

The lowering of carbon emissions due to a shift from coal-based to natural gas-based generation comes about because, as mentioned earlier, coal is twice as emission-intensive as natural gas. Also, newer technologies such as combined cycle generators and combined heat and power systems tend to reduce CO2 emissions compared to traditional generators. In these newer systems, waste heat is captured to either generate electricity or displace energy used for heating and cooling (DOE – US, 2000). However, this reduction in CO2 and even SO2 emissions resulting from the shift in the generation mix from coal to natural gas may be impeded by higher natural gas prices and by the limited number of sites available for natural gas-based generation capacity development that are usually held by incumbent firms. Higher equipment prices for natural gas-based generation capacity due to higher demand because of the generation mix shift may also dampen entry of natural gas-based generation capacity (Burtraw et al., 2001).

While restructuring legislation may induce a generation mix shift from coal to natural gas, if restructuring is accompanied by the introduction of real time pricing, then this shift from coal to natural gas may be impeded in specific locations because real time pricing leads electricity demand to shift from peak demand periods to off-peak demand periods. In some locations, off-peak demand is met through coal based generation whereas peak demand is met by natural gas-

[6] Of course, to the extent that Carbon Capture and Storage (CCS) is effective, carbon emissions could be reduced even while coal continues to be used for generation. However, this technology is not tied specifically to electricity generation, and at least in Alberta, cannot be viewed as resulting from electricity market restructuring.

based generation (Palmer, 2001). Thus, the lowering of carbon emissions through restructuring may be countered by an opposing effect from real time pricing. However, to the extent that real time pricing contributes to reduced consumption due to intelligent electronic monitors, the effect on emissions may be mitigated (Burtraw et al., 2001).

In a restructured market, apart from the impact of real time pricing, other features of competition may also impact the generation mix and hence carbon emissions. If competition leads to cross-region electricity trade, and hence serving of distant customers, then to the extent that natural gas-based capacity is situated near load, coal-based generation may displace natural gas-based generation, so that carbon emissions may increase as a consequence.[7] However, if in long distance electricity provision, the transmission providers make profits due to congestion pricing, new transmission investment will be impeded, which would then provide incentives to have generation situated near load, and to the extent these are natural gas-based plants, carbon emissions may be reduced. Carbon emissions could also be lower because less generation would be required to meet load due to reduced transmission losses (Burtraw et al., 2001).

While nuclear capacity is currently non-existent in Alberta, in the US context it has been argued that restructuring legislation may lead toward phasing out costly nuclear-based generation plants, which would have an effect of increasing CO2 emissions (Palmer, 2001). However, to the extent that competition increases the efficiency of nuclear plants and hence their longevity, CO2 emissions might be expected to decline. The net effect on emissions due to nuclear-based generation would then depend on these two opposing effects (Palmer, 2001).

In conclusion, the direction of the impact of restructuring on carbon emissions through the generation mix channel is not clear. While on the one hand restructuring legislation would tend to shift the generation mix from coal to natural gas, thus lowering carbon emissions, on the other hand, because of real time pricing and enhanced long-distance electricity trade, the generation mix may be shifted from natural gas to coal, thereby increasing carbon emissions. The net effect on carbon emissions would depend on the relative magnitudes of these two opposing effects. In fact even the direct impact of restructuring on lowering carbon emissions through shifting the generation mix from coal to natural gas is unclear based on the results of the Haiku simulation model. According to this model, restructuring would increase carbon emissions because of a shift from natural gas-based to coal-based generation due to the cheaper costs of coal-based generation and also because of lower electricity prices and hence increased electricity demand. Also, according to the Haiku simulation model, the lowering

[7] Coal plants are more carbon emission intensive and load/population centres usually avoid having huge coal plants located nearby. However, natural gas plants are less than half as carbon emission intensive, and given technological improvements, have minimum efficient scale much lower than those of coal plants.

of carbon emissions due to an elimination of real time pricing will not be enough to offset the increases in carbon emissions due to restructuring legislation (Burtraw *et al*, 2002).

These studies indicate that any effect of restructuring on the generation mix and hence carbon emissions is quite complex. They also highlight the significance of the generation mix in explaining any change in carbon emissions. The analysis also indicates a need to separate out the influence of restructuring on the generation mix from the effects of all other influences in order to properly gauge the role of restructuring in impacting carbon emissions.

6.4.2 Efficiency

Restructuring, by fostering competition, provides incentives to improve generator efficiency by lowering heat rates, which will reduce CO2 emissions (US DOE, 2000), and also the output rate measured as carbon emissions per kWh of generated electricity (Palmer, 2001). In fact, any increase in CO2 emissions due to an unfavourable shift in the generation mix can be countered by greater incentives to lower heat rates and hence efficiency in a competitive market. More specifically, according to Burtraw et al. (2001), in the short run, increases in electricity consumption would be met by more polluting and cheaper coal plants, and hence would contribute to an increase in emissions. In the long run, however, due to efficiency improvements and investment in cleaner plants, emissions could be reduced, depending on the relative price of fuels.

It may be concluded that while the impact of restructuring on carbon emissions through the generation mix is ambiguous as it is contingent on other factors, restructuring *ceteris paribus* clearly lowers carbon emissions by inducing increased efficiency of the generation plants.

6.4.3 Electricity Price

If restructuring yields lower electricity prices, then the output substitution effect implies that electricity consumption will be substituted for other types of (fossil) fuel consumption, thereby reducing carbon emissions. However, lower electricity prices would lead to increased electricity usage and hence increased emissions, given a fixed generation composition as well as controlling for the impact of any increased efficiency, demand elasticities and the implementation of price caps (Burtraw *et al*, 2001). This indicates that the effect of restructuring on carbon emissions through lowering of electricity prices depends on the relative strengths of the output substitution effect and the impact of higher electricity usage. Lower electricity prices also impede the penetration of capital-intensive renewable-based generation in the electricity market, as renewable-based generation is high cost, and hence contribute toward higher carbon emissions (Palmer, 2001).

Thus, the effect of restructuring on carbon emissions through the electricity price is not clear because of the different channels through which lower electricity prices impact carbon emissions, especially when it is also unclear whether electricity prices would be reduced or increased in the post-restructuring environment.

6.4.4 Demand Side Management (DSM) Programs

Demand Side Management (DSM) programs, which include time-sensitive pricing, rebates for retrofitting, and power-efficient appliance installations, were initiated in Canada in the 1980s (Cohen, 2006). In a post-restructuring environment, the incentives toward DSM programs will be reduced, due to competition, and would probably require transition charges akin to stranded cost charges for their continuation (Down et al., 2003). In fact according to Burtraw *et al* (2002), under restructuring, DSM programs may come to an end. It may be concluded that to the extent that restructuring impedes DSM programs and eliminates mandatory programs for conservation and mandatory investment in cleaner technologies (Burtraw et al, 2001), carbon emissions can be expected to increase in the post restructuring environment, holding everything else equal.

6.4.5 Green Power

Aspects of restructuring, like the renewable portfolio standard (RPS) which requires that renewable-based generation meet a fixed percentage of total generation, encourage renewable-based generation and hence lower carbon emissions. Other aspects of restructuring that aim to boost renewable-based generation include special exceptions for transmission and distribution access for environmentally-friendly technologies. Alternatively, net metering may also reduce the needs from conventional generation, which may also reduce emissions.[8] Of course it is not necessary that promotion of green power through RPS and other policies be part of restructuring initiatives, as it will be noted later in Section 6.4.6 that new products often associated with restructuring efforts have been introduced in both restructured and non-restructured US states (US General Accounting Office GAO, 2002). However, Pomorski (2006) notes that restructuring could have an impact on regulatory policies like RPS, and to the extent that restructuring is specifically associated with policies like RPS, or to the extent that restructuring initiatives make RPS more feasible, a case can be made for restructuring promoting green power through policies like RPS.

However, to the extent that restructuring impedes the penetration of renewable-based generation due to the risks in recovering the higher cost of capital in a competitive setting; there will be input substitution toward cheaper but

[8] According to Burtraw et al. (2001), “net metering is the practice of allowing customers with small renewable generating facilities that are interconnected with the local distribution company to sell all generation in excess of their own demand back to the grid at retail rates, effectively allowing the meter to run backwards”.

dirtier fuels like coal, which would contribute toward increasing carbon emissions. Moreover, to the extent that competition delays the introduction of newer environmentally-friendly technologies that may have longer gestation periods, the decline in emissions may be lowered (Burtraw *et al*, 2001). Thus, the effect of restructuring on carbon emissions through the green power channel is ambiguous.

6.4.6 Impacts Without Restructuring

The above analysis shows that the impact of restructuring on carbon emissions through the various channels, specifically those where the effect of restructuring is ambiguous (generation mix, electricity price, and green power), depends on the specific characteristics of the restructuring that is adopted in a particular jurisdiction. In fact, any competitive market created by restructuring legislation appears to have an ambiguous impact on GHG emissions. On the one hand, competitive markets may encourage emission trading, which can contribute toward determining least cost ways of complying with environmental standards. On the other hand, in competitive markets, generators have a limited opportunity to recover costs of environmental standards compliance, and hence have higher incentives to resist new environmental regulations (Down et al., 2003).

Since the impact of restructuring on carbon emissions depends on the type of restructuring that is implemented, it is important to note that carbon emissions will be reduced by restructuring only if it is designed to promote renewable-based generation and electricity conservation (Palmer, 2001). Moreover, policies within restructuring reform, like renewable portfolio standards, subsidies and tax benefits, and adequate electricity rates to renewable energy producers also help promote greener generation (Poch, 2001).

While restructuring designed in a specific manner may help reduce carbon emissions, it is not a necessary pre-requisite for that objective. In fact it has been observed that new products, often associated with restructuring efforts, like green power, real-time pricing, and energy-efficiency services, have been introduced in both restructured and non-restructured US states (US General Accounting Office GAO, 2002). Likewise, policy instruments such as subsidies and tax benefits and renewable portfolio standards as well as environmental legislation are not necessarily included as part of a particular jurisdiction’s restructuring reform. Thus, it is essential to separate the effect of restructuring on carbon emissions from the influence of other variables. One way to achieve such separation is through the use of a structural model of the determinants of carbon emissions, much in the same manner as the model for electricity prices developed in the previous chapters. The next section deals with the determinants of a structural model of carbon emissions.

6.5 Determinants of CO_2 Emissions

In this section some of the studies explored in Section 6.4 will be revisited to pinpoint the determinants of carbon emissions in the context of the electricity market, in order to facilitate the specification and subsequent estimation of a structural model of carbon emissions and thereby to study the impact of restructuring on those emissions.

According to Palmer (2001) carbon emissions are increased by lower electricity prices and the retirement of nuclear plants, whereas they are reduced by lowering of heat rates, increased reliance on renewable-based generation, and through energy-efficiency investments. Moreover, an increase in natural gas prices relative to coal prices may induce a shift toward coal-based generation and hence raise carbon and SO_2 emissions. Likewise, in the context of studying the effects of restructuring on emissions, Burtraw *et al* (2002) identify the generation technology mix, plant efficiency, and electricity prices as key variables through which restructuring impacts carbon and other GHG emissions. While these variables can be included in a structural model of carbon emission, Burtraw *et al* (2002) indicate that the most important determinants of carbon emissions remain the fuel mix and total electricity generation. However, Down et al. (2003) state that increased electricity demand and lower natural gas prices are the most significant determinants of NO_x and CO_2 emissions.

Many of the variables enumerated above are also highlighted as being important by a US DOE (2000) study, according to which the primary factors that affect CO_2 emissions due to electricity generation are electricity demand growth, the type of fuel, energy sources of generation and the thermal efficiency of the plants. Factors which affect these primary factors include economic growth, the electricity price, imported electricity, weather, fuel prices, the amount of non fossil fuel-based generation, demand side management (DSM) programs that encourage energy efficiency, technology, environment legislation, and the quality of fuels as measured by their carbon content and heating value in units of BTU.

In summary, the electricity price, heat rates, renewable-based generation, fuel prices, generation composition, electricity demand, energy-efficiency investments, weather, imported electricity, technology, and environment legislation can all be considered as potential explanatory variables in a structural model of carbon emissions. While the directions of the impacts of heat rates, renewable-based generation, fuel prices, generation composition, electricity demand, energy-efficiency investments, weather, imported electricity, technology and environment legislations on carbon emissions seems clear a priori, the effect of the electricity price is ambiguous in a Canadian context. While an increase in Canadian electricity prices could curtail demand and hence emissions, if that price increase is due to exports to the US, then higher prices will be associated with higher production and emissions (Cohen, 2006).

While in principle the impact of restructuring on carbon emissions can be studied through a structural model by controlling for the determinants of these emissions as identified from the literature, as discussed in Section 6.4, restructuring itself may have influenced several of these determinants. Thus, a proper evaluation of the effect of restructuring on the environment would require the use of a counterfactual analysis (Burtraw et al., 2001). Put simply, the impact of restructuring on such variables will have to be dealt with to separate the role of electricity market restructuring on carbon emissions from the impact of other variables.

The approach that is required is therefore similar to the methodology used in the study of electricity prices provided in previous chapters. First a structural model of carbon emissions will be estimated in the context of the electricity market in the pre-restructuring period. Having estimated the model, in order to study what would have been likely to have happened to carbon emissions in the absence of electricity market restructuring the next step is to remove the effects of restructuring on the explanatory variables in the post-restructuring period. This modification of the values of the relevant explanatory variables in the post-restructuring period is determined in a similar manner to that used in Chapter 5 in the context of a model of electricity prices, basically through the study of data from US jurisdictions. Next, using these modified values of the explanatory variables in the post-restructuring period with the estimated model of carbon emissions from the pre-restructuring period, a set of counterfactual carbon emissions in the post-restructuring period can be extracted from the model forecasts. A comparison of these counterfactual emissions with those actually observed in the post-restructuring period then allows a determination of whether carbon emissions declined in the post-restructuring period relative to what they would have been in the absence of the restructuring initiatives. In this manner the role of electricity market restructuring on carbon emissions can be clearly identified.

As far as the structural model is concerned, data availability pertaining to the factors identified previously will guide the selection of explanatory variables as well as help determine the period of estimation. Since, according to Swenarchuk and Muldoon (1996), energy providers moved toward self regulation on environmental and labor issues – even before the implementation of electricity restructuring (Cohen, 2006) – the post-restructuring period might be better defined not by the date of the implementation of restructuring but by a few years prior to this date.[9] With sufficient data, sensitivity analysis could be conducted to test for the year used to separate the pre- and post-restructuring periods, just as was done in the context of the electricity prices in the previous chapters.

[9] This implies there are only two periods. However, there could also be a "between" period, that is, between pre restructuring and post restructuring. This might help deal with the oddity of defining the post-restructuring period as beginning before restructuring has occurred, although it makes sense to define pre-restructuring as ending some years prior to the implementation date for restructuring.

Unfortunately, as discussed in Section 6.7, there are only limited data available for our empirical analysis, and not enough to permit such sensitivity analysis.

6.6 A Model of the Role of Various Factors in Determining CO2 Emissions

As will be seen in Section 6.7, data on carbon emissions are available only on an annual basis from 1990 to 2006, which provides only 17 data points for regression analysis. While data on some explanatory variables like energy efficiency investments are not available at all, in view of the limited data points for the dependent variable, only the key explanatory variables identified in the previous sections will be considered for further analysis. For the most part, data on these explanatory variables are available on a yearly basis, and even where monthly data were collected for some of the variables, these monthly data series could not be used in subsequent analysis since not all variables are monthly. In addition, data pertaining to US jurisdictions that are employed to control for the impact of restructuring on the explanatory variables are only available on a yearly basis from 1990 onwards. Thus, regression analysis is limited to annual data.

For the purpose of building a structural model for the determinants of carbon emissions (**CO2em**), the key variables considered are those that capture the generation mix, efficiency, the electricity price, electricity demand, and green power.

As mentioned earlier, data on energy efficiency investments are not available so that this variable cannot be included in the model. As far as environment legislation is concerned, three plans/pieces of legislation were introduced in Alberta in 2002, 2007, and 2008.[10] While the Kyoto Protocol was signed in 1997, it is not clear whether any concrete steps were taken to effectively implement the contents of that agreement in Canada, and particularly in Alberta. A similar comment applies to the contents of the 2002 legislation in Alberta.[11] Thus, no variable pertaining to environmental legislation is included in the model. Also, given that Alberta has a small amount of inter-provincial trade with BC and Saskatchewan in terms of electricity, no variable reflecting the amount of imported electricity is included in the model. In general, these variables that cannot be included in the model are expected to have only marginal relevance.

In view of these limitations, explanatory variables that capture the generation mix, efficiency, the electricity price, electricity demand, and green power will be considered for the purpose of modeling the determinants of carbon emissions. Generation mix and green power can be captured by the shares of coal-, natural gas- and renewable-based generation capacity. Since these three

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[10] Albertans and Climate Change: Taking Action – 2002, Climate Change and Emissions Management Amendment Act and Administrative Penalty Regulation – 2007 (Drexhage et al., 2007), Climate Change Strategy – 2008 (Alberta Environment)

[11] The Legislative Acts of 2007 and 2008 are ignored here since they fall outside our sample period of 1990-2005.

sources provide virtually all Alberta generation capacity, only two of the three can be included in order to avoid issues of multicollinearity. As an alternative, the generation mix can be captured by the share of renewable based capacity and the ratio of coal-based generation capacity to natural gas-based generation capacity. As a form of sensitivity analysis, relative fuel prices (coal to natural gas) are also considered as an alternative to this ratio.

Efficiency can be captured by coal-based and natural gas-based heat rates. As mentioned previously, heat rates measure the amount of fuel energy (kJ) required to generate a unit of electricity (kWh). The lower this figure, the higher the efficiency of the power plants, as less energy is utilized to generate the same amount of electricity. In view of the small sample size, rather than including these variables separately, a more parsimonious specification uses the ratio of the coal-based heat rate to the natural gas-based heat rate.

Technological development likely plays a role in influencing efficiency in the electricity market. To allow for such effects, a time trend could be introduced in the model to reflect technological change.[12] However, it is likely that technological change in terms of carbon emissions is reflected in a decrease in emissions per unit of output (emissions intensity), rather than just a decrease in emissions, since the latter could be offset by increases in economic activity. In a model of carbon emissions, one way to allow for the effect of technological change on emissions intensity would be to include a quadratic term in output (real GDP), since this would allow the effect of increased output on total emissions to depend on the level of output. To the extent that technological progress has reduced emissions intensity, the coefficient on this quadratic output term would be expected to be negative. As an alternative, the product of output and a time trend could be used, since this would allow the effect of increased output on emissions to depend on time, and again a negative coefficient would be expected.

Both the electricity price and electricity demand are expected to have similar types of effects on carbon emissions, since a change in the electricity price would be expected to cause a change in electricity demand, which would then impact carbon emissions. To keep the model parsimonious therefore, only one of these variables is included. Initially, the electricity price will be considered, but in alternative specifications, real GDP and Heating Degree Days (HDD) will be used as proxies for electricity demand. A possible advantage of real GDP in this regard is that it would reflect the effects of other activities besides just electricity production (and consumption) on carbon emissions.

Thus, the basic model is represented by equation (6.1):

[12] Since the effect of technological change on emissions is unlikely to be constant, ideally a stochastic time trend would be included. However, the sample size is too small to allow this type of specification, and it is not conducive to forecasting in the post-restructuring period.

(6.1) CO_2 emissions (kt) = f [capacity variables, heat rates, technical progress, demand]

where:

{capacity variables} =	(a)	share of coal-based capacity <u>and</u> share of renewable-based capacity, or
	(b)	ratio of coal-based capacity to natural gas-based capacity <u>and</u> share of renewable-based capacity, or
	(c)	relative fuel prices (coal / natural gas) <u>and</u> share of renewable-based capacity
{heat rates} =	(a)	coal-based heat rate <u>and</u> natural gas-based heat rate, or
	(b)	ratio of coal-based heat rate to natural gas-based heat rate
{tech. progress} =	(a)	squared real GDP, or
	(b)	real GDP × time trend
	(c)	time trend
{demand} =	(a)	electricity price, or
	(b)	real GDP, or real GDP growth, or
	(c)	HDD

6.7: Data Analysis

6.7.1 CO2 Emissions

Data on GHG emissions as a whole are available from Appendix 12 of the Environment Canada annual publication entitled "National Inventory Report, 1990-2005 - Greenhouse Gas Sources and Sinks in Canada", wherein GHG emission data in units of kilotonne CO_2 equivalent for Alberta for Electricity and Heat Generation are provided from 1990 – 2005. These data incorporate electricity generation from both utilities as well as industry. Data specifically on CO_2 emissions are available from 2003 – 2005 from the same publication. Appendix 9 entitled "Energy Intensity Tables" provides data from 1990 – 2005 for GHG emissions separately from coal and natural gas used in electricity generation by public utilities. Appendix 9 from the 2004 report of the same title presents data from 1990 – 2004 for GHG emissions from coal and natural gas used in electricity generation for total utilities and for industry as a whole. It is not clear how the data from both the Appendices 9 from different annual reports can be reconciled.

Data on CO_2 emissions, specifically, are available for power plants from 2003 – 2006 from the Alberta Environment annual publication entitled "Alberta Environment Greenhouse Gas Emissions Summary". Data on CO_2 emissions are also available from the Environment Canada publications. Jointly, the publications entitled "Canada's Greenhouse Gas Inventory: 1997 Emissions and Removals with Trends", and "Trends in Canada's Greenhouse Gas Emissions (1990-1995)" contain data on CO_2 emissions from electricity and steam generation in Alberta for 1997 and power generation for 1990 – 1995, respectively, in units of kilotonnes. Similarly, the Environment Canada website Search Facility provides data on CO_2 emissions for the 2004 – 2006 period for the Electric Power Generation, Transmission and Distribution category for Alberta.

The focus of this paper is on CO_2 emissions, and while the above sources indicate that data on GHG emissions from the electricity sector are available from 1990 – 2005, data on total CO_2 emissions are available only for select years. Data on Alberta CO_2 emissions for 1990 – 2005 from electricity and heat generation from utilities and industries were obtained from the Emissions Inventory Specialist at the Climate Change Policy Unit of the Environmental Assurance Division of Alberta Environment. Data on CO_2 emissions from the various sources are presented in Table 6.1.

Comprehensive data from 1990 – 2005 from Alberta Environment match with the 2003 – 2005 data available from the Environment Canada annual publication "National Inventory Report". However data from the other sources do not match with the comprehensive data set, which is due to the fact that while data from Alberta Environment are reported for electricity generation from the utility and industry segment, data from the other sources are presented specifically for utilities. While data specifically from utilities further subdivided on the basis of fuel type would be ideal, data limitations require that the yearly data from 1990 – 2005 from Alberta Environment be used for the analysis.

Table 6.1: Data on Alberta CO2 Emissions

Year	kilotonnes	SECTOR and data source
		Electricity and Heat Generation
1995	47,900	Trends in Canada's greenhouse gas emissions (1990-1995)
1996	48,500	Canada's greenhouse gas inventory : 1997 emissions and removals with trends
		Electricity and Steam Generation
2003	54,500	Canada's Greenhouse Gas Inventory, 1990-2003
2004	52,400	National Inventory Report, 1990-2004 - Greenhouse Gas Sources and Sinks in Canada
2005	53,000	National Inventory Report, 1990-2005 http://www.ec.gc.ca/pdb/ghg/inventory_report/inventory_archi_e.cfm
		Power Plants
2003	46,250	Alberta Environment greenhouse gas emissions summary http://environment.alberta.ca/documents/2006_GHG_Report.pdf
2004	49,017	
2005	50,176	
2006	51,287	
		Alberta, NAICS Code: Electric Power Generation, Transmission and Distribution (2211)
2004	49,016	Search Facility Data - Results http://www.ec.gc.ca/pdb/ghg/onlineData/dataSearch_e.cfm
2005	50,177	
		Electricity and Heat Generation
1990	39,900	Utility and industry Emissions Inventory Specialist Climate Change Policy Unit Environmental Assurance Division Alberta Environment.
1991	41,800	
1992	45,000	
1993	45,700	
1994	49,300	
1995	48,900	
1996	48,100	
1997	50,900	
1998	51,400	
1999	49,800	
2000	51,800	
2001	53,200	
2002	52,700	
2003	54,500	
2004	52,400	
2005	53,000	

The information on Alberta CO2 emissions provides 16 data points that can be used for regression analysis. A preliminary examination of the data suggests that CO2 emissions have increased in the post-restructuring period. If the data are divided in two ways, as shown in Table 6.2, based alternatively on the year of wholesale (1996) and retail (2001) restructuring, a comparison of the pre- and post-restructuring average values of CO2 emissions clearly indicate a rise in CO2 emissions by 14.81% and 11.89% respectively, in the latter period.

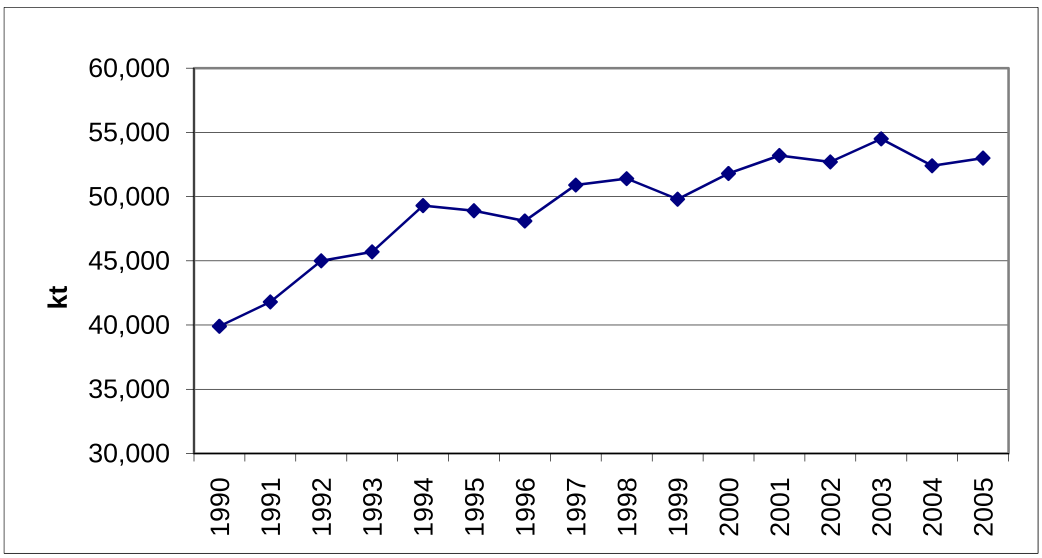
However, the trend in CO2 emissions can be better gauged visually, as shown in Figure 6.2.

Table 6.2: Average CO2 Emissions in Alberta by Sub-Period

Period	Years	Average
Pre- and Post Wholesale Restructuring Periods	1990-1995	45,100
	1996-2005	51,780
Pre- and Post Retail Restructuring Periods	1990-2000	47,509
	2001-2005	53,160

Figure 6.2 reveals an increasing trend in CO2 emissions in Alberta. However, it also indicates that while emissions grew steeply from 1990 to 1994, the increase in CO2 emissions has not been as steep in the post-1994 period. Since Canada signed the Kyoto Protocol in 1997, the relatively flatter portion of the graph in the post-restructuring period could be at least partially due to restructuring efforts, changes resulting from the signing of the Kyoto Protocol, or both.

Figure 6.2: Alberta CO2 Emissions (CO2em)



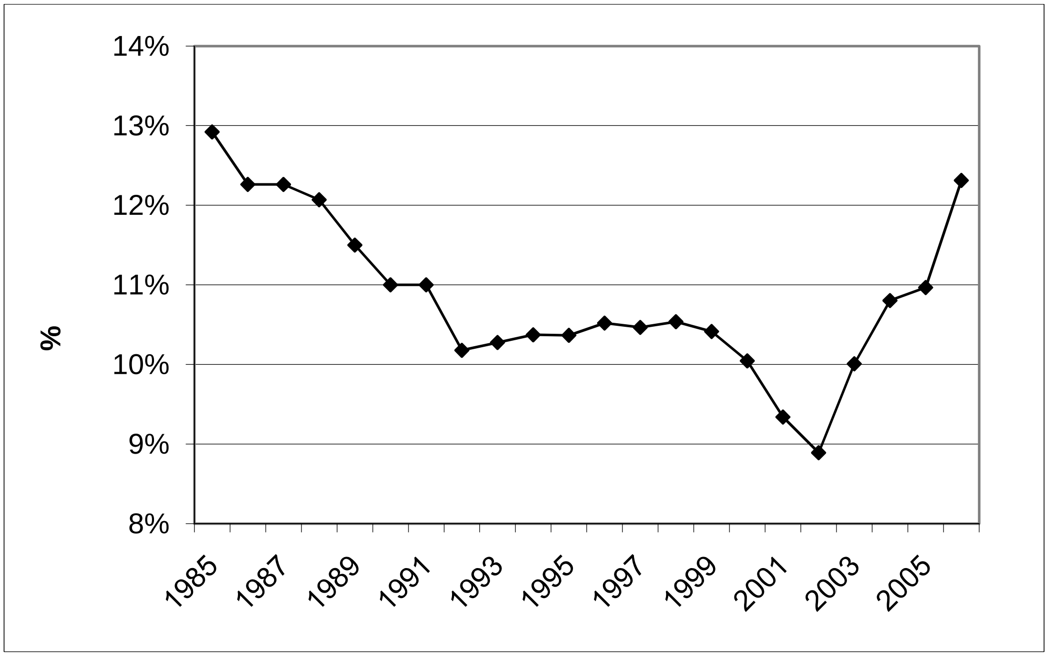
6.7.2 Renewable-based Generation Capacity

Data on renewable-based generation capacity, as well as on actual generation, are available from the Alberta Energy and Utilities Board Annual Statistics of the Alberta Electric Industry (AEI). Capacity in units of MW and generation in units of GWh are available from 1962 to 2002; data from 2003 to 2006 had to be patched up from different sources. Renewable-based generation and capacity comprise hydro, wind, biomass, and waste components. While capacity data for these four components are available, generation data for the biomass and waste components are not available after 2002. In view of these considerations, as a measure of green power, total renewable-based capacity is used in the structural modelling.

As far as renewable-based generation capacity is concerned, data for hydro-based capacity were inferred from Alberta Energy Utilities Board (EUB) annual reports. These reports indicate that hydro-based capacity increased by 4% in 2003 over its value in 2002, and the graphs on hydro-based capacity indicate that from 2003 to 2005 there was no change in this capacity. Data on wind-based capacity are explicitly available from the EUB reports in units of MW. As far as the values for the biomass and waste segment are concerned, data for 2005 and 2006 are available from two reports by the Alberta Electric System Operator (AESO). The data for 2003 and 2004 were interpolated by substituting in the average value of biomass and waste based capacity for 2002 and 2005. Subsequently, the hydro, biomass and waste, and wind-based generation capacity values were summed to obtain total figures for the renewable sector. This total figure was then divided by the total capacity to obtain the share of renewable-based capacity.

The graph of the share of renewable based capacity from 1985 – 2006, provided in Figure 6.3, indicates that, until 1992, the share of renewable based capacity was decreasing; thereafter it levelled at around 10% of total capacity until 2000. This indicates that in the period immediately preceding and following wholesale electricity market restructuring, the share of renewable-based capacity does not appear to have been affected by the restructuring process. From 1999 to 2002 there was a decline in that capacity, perhaps due to the uncertainty caused by the 1998 *Electric Utility Amendment Act*. However, if the values of the components of renewable-based capacity are closely examined, they reveal that while hydro-based capacity has always been roughly constant, wind-based capacity grew close to threefold from 2001 – 2005, although since natural gas-based capacity increased drastically, by as much as 17% in 2003, perhaps this huge change has dwarfed the share of renewable-based capacity. It is important to note that since 2002, there has been an upward surge in the share of renewable-based generation capacity.

Figure 6.3: Share of Renewable-based Generation Capacity in Alberta



6.7.3 Data on Other Explanatory Variables

Data on coal- and natural gas-based generation capacity, coal- and natural gas-based heat rates, the electricity price, HDD, and real GDP have been defined and analyzed in Chapter 4.

6.8: Estimation of a Model of the Determinants of Carbon Emissions

Following from the model developed in Section 6.6 and data considerations in Section 6.7, the base model for CO2 emissions in kilotonnes that is estimated has the form:

(6.2) CO2 emissions (kt) = f [relative share of coal and natural gas capacity, share of renewable-based capacity, coal- and natural gas-based heat rates, electricity price, time trend (t)]

A number of possible alternative formulations were suggested in Section 6.6; here we limit the alternatives that are considered to (i) replacing electricity prices with economic growth or with HDD, and (ii) using relative fuel prices to replace the relative share of coal and natural gas capacity variable.[13] Altogether, four different model specifications are estimated.

Although the procedure to be used to assess the effects of restructuring on CO2 emissions is analogous to the method used previously to examine the effects of restructuring on electricity prices, as developed and applied in Chapter 5, in view of data limitations, a different approach is used initially. Specifically, we begin in Section 6.8.1 by focusing on the entire 16 year period for which annual data are available, 1990 to 2005. In this way it is possible to examine various issues associated with model specification and estimation that cannot be examined using the shorter pre-restructuring period for which data are available. In this initial approach, a dummy variable is included in the model to allow for the possibility that CO2 emissions differ pre- and post-restructuring. However, no account is taken of the possibility that the values of the explanatory variables included in the model may themselves be affected by restructuring. In subsequent sections, the model is re-estimated using just the pre-restructuring period and, following adjustments to the explanatory variables in the post-restructuring period to reflect the possible effects on them of restructuring, the estimated model is used to obtain predictions of CO2 emissions for the post-restructuring period which are compared to actual emissions for that period in order to assess the effects of restructuring on these emissions.

6.8.1 Estimation for the Entire 1990 to 2005 Period

In this initial approach, the model specification in (6.2), as well as the alternative described above, is supplemented with a dummy variable so as to distinguish the pre-restructuring period from the post-restructuring period and hence allow for a possible impact of restructuring on carbon emissions. In contrast to the model of electricity price determinants, where the cost of service model that was in place in the pre-restructuring period did not operate in the post-restructuring period, a similar model of CO2 emissions can be reasonably assumed to apply in both sub-periods, so that the use of a dummy variable to reflect changes between these two sub-periods is justified. Of course ideally this dummy variable would be interacted with the other explanatory variables to allow their effects on CO2 emissions to also differ in the two periods, but unfortunately the small sample size precludes such an approach. The variables used in the regression analysis are as follows:

[13] Consideration of other alternatives would best be undertaken when longer data series are available.

Table 6.3: Variables used in the Analysis

Mnemonic	Description
CO2em	Carbon Dioxide emissions in kilotonnes (variable to be explained);
Cratio	Share of coal based generation capacity / share of gas based generation capacity;
Renew	Share of renewable based generation capacity;
Hratio	Coal based heat rate (GJ/GWh) / natural gas based heat rate (GJ/GWh);
Elecpr	Residential electricity price (c/kWh);
T	Time trend;
Retail	Dummy variable 0 for the pre restructuring years 1990 – 2000 and 1 for the post restructuring years 2001 – 2005;
Pratio	Price of coal to electricity producers ($/GJ) / price of natural gas to electricity producers ($/GJ);
HDD	Heating Degree Days;
Growth	Real GDP growth.

The results based on OLS regressions of the four variants of the model are reported in Table 6.4 below. These four variants, labelled Models I to IV in Table 6.4, differ on the basis of five variables – **Cratio**, **Pratio**, **HDD**, **Growth**, and **Elecpr**. For all four models, the signs of the coefficients on the variables are as expected except **Cratio** for Models I and III and **HDD** in Model III, although the coefficients on these variables are not statistically significant even at a 10% significance level.

The time trend, **T**, is statistically significant in all four models. While the time trend is used to capture technological progress, technological improvements are perhaps likely to be better reflected in the ratio of Carbon Emissions to output rather than in the level of carbon emissions themselves, and as a result the coefficient on **T** is positive, showing that the level of carbon emissions is generally increasing. The dummy variable **Retail** is statistically insignificant for all models. Focusing exclusively on statistically significant parameters, the sign on **Renew** is significant at 5% significance level in Model IV and has the expected negative sign, while the growth rate is significant at 10% significance level in Model 4 and has the expected positive sign. Based on statistical significance and signs of the coefficients, Model IV appears to be better than the other models. However, even in Model IV, as with the other models, it is the constant term and the time trend that are strongly statistically significant at the 1% significance level, which is perhaps indicative of the relatively minor explanatory power of the remainder of the model. This would suggest that any counterfactual carbon emissions obtained from Model IV, which appears to be the best among the four models, would need to be viewed cautiously. As with the electricity price models in Chapters 4 and 5, it is possible that the insignificance of several of the variables may be due to non-stationarity. This issue is addressed below.

Table 6.4: Results of Estimation for Entire Sample Period, 1990– 2005

Explanatory variables	Model I	Model II	Model III	Model IV
Cratio	-264.73		-250.25	146.76
	-0.19		-0.18	0.15
Renew	-1436.8	-1503.4	-1384.3	-1723.8*
	-1.55	-1.60	-1.54	-2.76
Hratio	1800.7	2009.9	1879.1	1772.5
	0.87	1.16	1.05	1.51
Elecpr	-112.07	-142.56		
	-0.09	-0.11		
T	843.49*	886.40**	840.17*	818.8**
	2.69	3.99	3.22	4.67
Retail	-2,446.3	-2,304	-2,628.4	-1,599
	-1.14	-1.14	-1.65	-1.35
Constant	56222**	55567**	57307**	56123**
	4.20	3.91	5.22	8.54
Pratio		-8.15		
		-0.03		
HDD			-0.51	
			0.36	
Growth				281.14†
				1.98
df	9	9	9	9
R-squared	0.9229	0.9226	0.9239	0.9380
Durbin-Watson (DW)	2.43	2.45	2.33	2.63
Positive DW p-value	0.38	0.43	0.19	0.52
Negative DW p-value	0.62	0.57	0.81	0.48
JB normality p-value	0.61	0.68	0.72	0.58
RESET test p-values				
- with squared terms	0.018	0.016	0.043	0.064
- with cubed terms	0.067	0.059	0.148	0.168
- with terms to the power 4	0.158	0.157	0.209	0.295
LM tests for autocorrelation				
1st order				3.80
2nd order				8.48*

Notes: 1. **, *, and † indicate significance at the 1%, 5%, and 10% levels, respectively.
2. Numbers below the respective coefficients are estimated t ratios.
3. In order to manage the coefficient on 'renew', the variable renew was multiplied by 100.

Ramsey RESET tests were conducted to test for model misspecification (functional form or omitted variables), and according to the p-values only Model IV seemed to exhibit no misspecification issues. Subsequent attention is therefore focused on Model IV. Breusch-Pagan and Breusch-Pagan-Koenker tests performed on Model IV, using one explanatory variable at a time, indicate no presence of heteroskedasticity related to any of the explanatory variables as shown in Table 6.5. A joint test of all variables also provided no evidence of heteroskedasticity.

Table 6.5: Tests of Heteroskedasticity for Model IV

Variable	BP	BPK
Cratio	0.001	0.003
Renew	1.32	3.61
Hratio	0.09	0.24
Growth	0.002	0.006
T	0.08	0.23
Retail	0.00001	0.00003
ALL Variables	2.07	5.66

Note: Critical value is 3.84 (df=1) for all tests involving individual variables, and 12.59 (df=6) for the test involving all variables.

The very high R^2 values for all the models in Table 6.4 might suggest that non-stationarity of some of the variables may be an issue for estimation, possibly resulting in spurious regressions, although evidence of autocorrelation would also be expected in such a case. The values of the DW statistics do not indicate first-order autocorrelation, although LM statistics (shown just for Model IV) suggest higher order autocorrelation may be an issue, although it must be kept in mind that these LM tests are asymptotic and are used here with a very small sample, so that conclusions from these tests may be unreliable here.

Given the potential problem of non-stationarity, and given the small number of data points which precludes effective testing using standard tests for unit roots, graphs of each of the variables were initially examined to identify the presence of unit roots or time trends. A visual inspection of Figures 6.2 to 6.6 indicates that except for carbon emissions (**CO2em**) – see Figure 6.2, and **Cratio** (Figure 6.4), where there seems to be evidence of a potential unit root in the series, all other variables appear to be stationary.

Figure 6.4: Coal/Natural Gas Capacity Ratio in Alberta (Cratio)

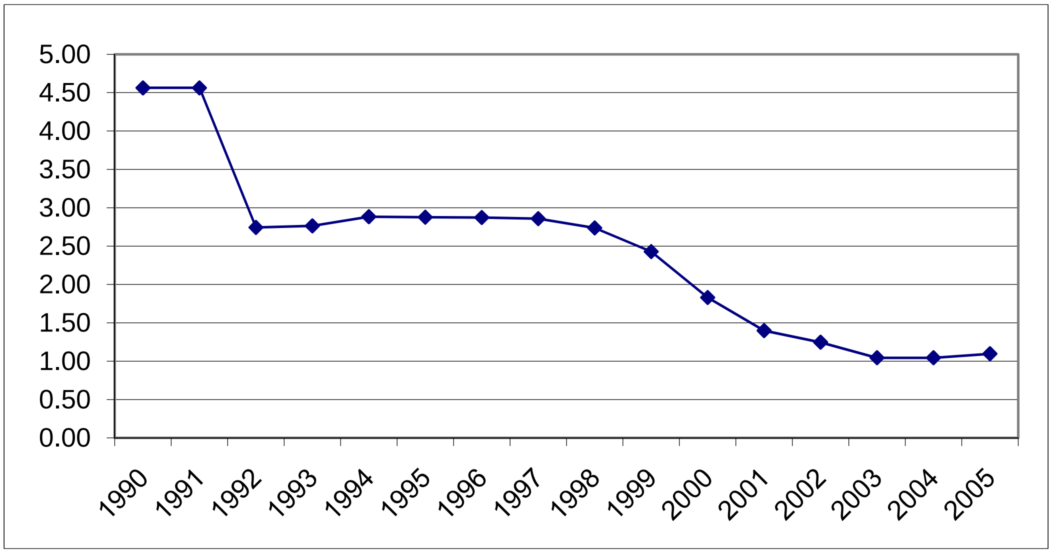


Figure 6.5: Ratio of Coal to Natural Gas Heat Rates in Alberta (Hratio)

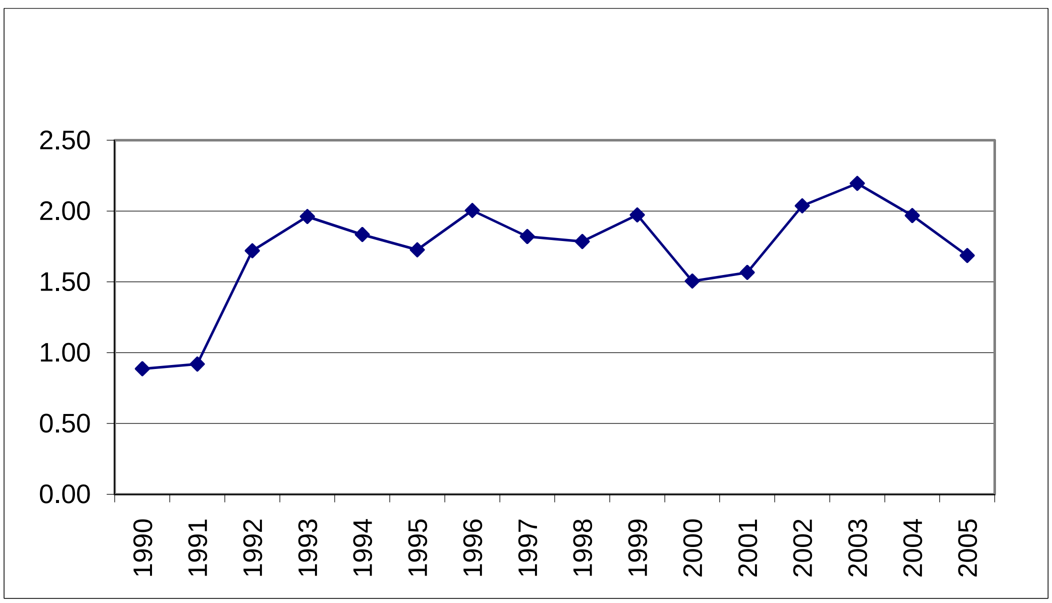
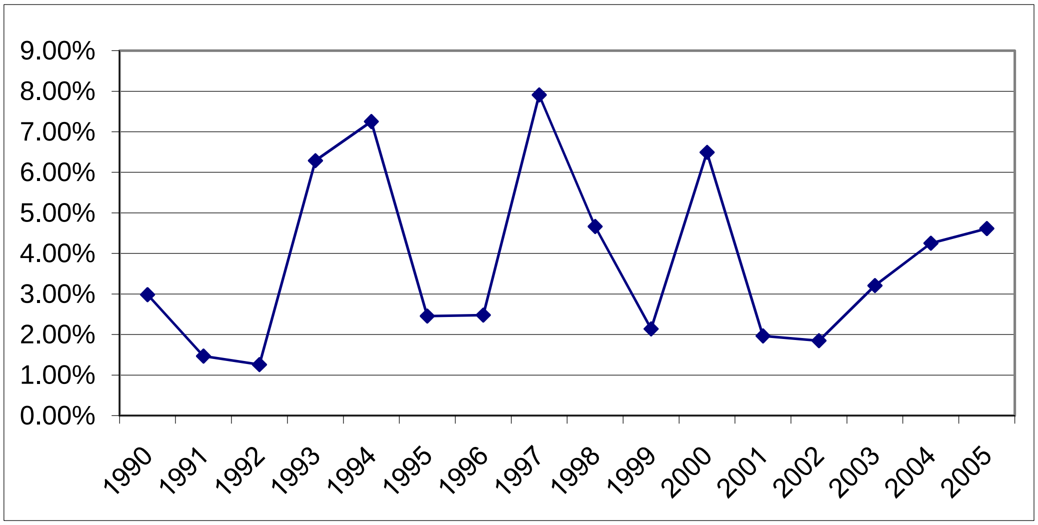


Figure 6.6: Percentage Growth Rate in Alberta (Growth)



Although unit root tests have poor properties in a small sample such as is available for analysis here, for completeness and as possible support for the graphical analysis, unit root tests were conducted using the EVIEWS software, where the strategy suggested by Elder and Kennedy (2001), as described in Chapter 4, was followed. Since the **CO2em** and **Cratio** variables exhibit a trend and the other variables do not, unit root testing for the former variables included a drift term and a time trend, whereas for the latter variables, unit root testing was conducted by including only the drift term. The testing strategy supports the graphical analysis, indicating the presence of a unit root for both **CO2em** and **Cratio** variables, but finding the other variables to be stationary.

Table 6.6: Unit Root Tests for CO2em and Cratio

Test Component		Drift and Time trend		Drift only		
		CO2em	Cratio	Renew	Hratio	Growth
Level ADF test statistic		-2.3	-3.35	-3.35	-5.66	-4.35
Critical values	1%	-4.8	-4.99	-4	-4	-4
	5%	-3.79	-3.88	-3.1	-3.1	-3.1
	10%	-3.34	-3.39	-2.69	-2.69	-2.69
1st difference ADF test statistic		-4.53	-3.99	N/A		
Critical values	1%	-4.89	-4.8			
	5%	-3.83	-3.79			
	10%	-3.36	-3.34			

Given that both **CO2em** and **Cratio** are found to be integrated of order 1, cointegration tests are used to determine if these two variables are cointegrated, in which case an error correction model could be used rather than a model that just includes first differences of these two variables. The results as shown in Table 6.7 below indicate that these two variables are not cointegrated. Thus, the appropriate model that accounts for possible non-stationarity issues would include first differenced values of **CO2em** and **Cratio**, along with the other (stationary) variables in levels form.

Table 6.7: Tests for Cointegration between CO2em and Cratio

Test	ADF tests without trend		ADF tests with trend	
	test statistic	Critical value	test statistic	Critical value
Z test	-8.75	-17.10	-8.45	-23.40
t test	-2.51	-3.04	-2.50	-3.50

Among the previous model specifications that were considered (Table 6.4), only Model IV indicates no presence of heteroskedasticity or model misspecification. The high DW p-values also indicate no issue with auto-correlation, although as mentioned earlier, LM statistics for higher order autocorrelation are less supportive. In view of the possible problem of non-stationarity, and the potential autocorrelation issue, six variants of Model IV were estimated to account for both unit roots and autocorrelation. In addition to OLS estimation with estimated standard errors based on the Newey-West procedure that will allow inference even if there is autocorrelation, AR1 and AR2 models were also estimated, and all three of these procedures were also used for the same model in which the **CO2em** and **Cratio** variables were first differenced (and denoted by **ΔCO2em** and **ΔCratio**, respectively). The results of these estimations are presented in Table 6.8.

Estimation results of Model IV with Newey-West corrected standard errors in Column (1) of Table 6.8 indicate the significance of all variables at least at the 5% significance level except for **Cratio** and **Retail**. This is slightly different from the basic Model IV estimation (Table 6.4) in which the **Hratio** variable was also statistically insignificant. Interestingly, in the models that allow for AR(1) or AR(2) autocorrelation, the variables tend to become strongly statistically significant and the R^2 increases, which might be viewed as supporting the view that these are spurious regressions, as suggested by the non-stationarity findings discussed earlier.

The results obtained when the models are estimated by first differencing the carbon and **Cratio** variables to account for unit roots are presented in Columns (5) to (7) of Table 6.8. Compared to the results for the levels model in Columns (2) to (4), the coefficient signs change for all variables except growth, renew and the constant. The coefficient signs in columns (5) to (7) indicate that increased coal-based capacity decreases emissions, increased coal plant efficiency increases emissions, technological progress reduces emissions and that electricity market restructuring has increased carbon emissions. The signs on all these variables except **ΔCratio** and **hratio** now make sense compared to the signs on these variables in the base case of Model IV. The sign on the **ΔCratio** variable seems counter-intuitive as it indicates that, ceteris paribus, for a 1 percentage point increase in the (change in the) relative capacity ratio, that is, an increase in coal based capacity versus natural gas based capacity, CO2 emissions decline in the range of 980 – 1700 kilotonnes. Likewise, the sign on the **Hratio** variable seems counter-intuitive as it indicates that, ceteris paribus, for a 1 percentage point increase in the relative efficiency ratio, that is, a decrease in coal plant efficiency versus natural gas plant efficiency, CO2 emissions decline in the range of 900 – 1850 kilotonnes.

Based on the variants of Model IV in columns (5) to (7) of Table 6.8, having controlled for capacity mix, efficiency, electricity demand, renewable capacity and technological development, the negative coefficient on the **Retail** variable indicates that electricity price restructuring seems to have increased carbon emissions. This conclusion differs from the levels version of Model IV, where electricity price restructuring had no statistically significant effect on carbon emissions. While the variants of Model IV in columns (6) and (7) of Table 6.8 indicate that all coefficients are statistically significant, and hence seem to be an improvement over Model IV, the unexpected signs on **ΔCratio** and **Hratio** are problematic. Thus, even after accounting for non-stationarity, any counterfactual carbon emissions obtained from these models would need to be viewed cautiously, for such counterfactual carbon emissions would only be as good as the model used to generate them. Of course these estimation results, including the lack of evidence of cointegration, would likely be improved by the use of longer time series data series, so that it may be useful to revisit the analysis and re-estimate the models once such data become available.

While the result from the differenced variants of Model IV may seem more appropriate because it accounts for possible non-stationarity, this finding does not take into account the possibility that some explanatory variables – particularly, **cratio**, **renew**, and **hratio** – have been affected by restructuring, and that this needs to be considered when drawing conclusions about the effects of restructuring on carbon emissions. This could not be done effectively in the estimation framework considered here, where restructuring just appears as a dummy variable. However, by utilizing a similar framework as in Chapter 5, with estimation for a pre-restructuring period, adjustments of the values of the endogenous explanatory variables in the post-restructuring period to account for the impact of restructuring, and then forecasting of carbon emissions for this latter period using the previously-estimated model, this problem can be rectified. This counterfactual approach, is considered in the next section.

Table 6.8: Results using Variants of Model IV

Explanatory variables (1)	Dependent Variable: CO2em			Dependent Variable: ΔCO2em		
	AUTCOV=1 (2)	AR1 (3)	AR2 (4)	AUTCOV=1 (5)	AR1 (6)	AR2 (7)
Cratio	146.76	642.75	1,067.6			
	0.22	0.83	1.81			
ΔCratio				-1,706.1**	-986.28*	-1,037.5**
				-10.14	-2.35	-4.35
Renew	-1,723.8**	-1,924.5**	-1,981.2**	-430.12	-681.51*	-566.57**
	-3.38	-4.21	-6.12	-0.99	-2.75	-4.63
Hratio	1,772.5*	2,372.8*	3,413.6**	-1,840.8*	-1,760.9*	-901.34†
	2.29	2.61	5.34	-2.53	-2.84	-1.97
T	818.8**	878.29**	901.63**	-288.71**	-288.07**	-265.02**
	5.71	7.03	12.58	-3.67	-5.90	-13.4
Retail	-1,599	-1,541.1	-1,296.5†	2,187.1*	1,813.3**	1,600.7**
	-1.53	-1.75	-1.83	3.18	3.84	7.09
Constant	56,123**	55,293**	52,794**	7,746	10,818**	8,232**
	14.38	11.74	19.77	1.53	3.62	5.64
Growth	281.14*	321.66*	314.87†	591.93**	496.89**	470.72**
	3.09	2.53	1.99	7.75	5.94	7.25
RHO1		-0.45	-0.80		-0.76	-1.33
RHO2			-0.69			-0.93
df	asymptotic	asymptotic	asymptotic	asymptotic	asymptotic	asymptotic
R-Squared	0.938	0.9496	0.9721	0.7015	0.8506	0.9399
DW	2.63			3.17		
JB normality p-value	0.58			0.83		
Ramsey test p-values						
- with squared terms	0.064			0.911		
- with cubed terms	0.168			0.931		
- with terms to the power 4	0.295			0.987		

Notes: **, *, and † indicate significance at the 1%, 5%, and 10% levels, respectively.

2. Numbers below the respective coefficients are estimated t ratios.
3. In order to manage the coefficient on ‘renew’, the variable renew was multiplied by 100.

6.8.2 Constructing the Counterfactual

To begin, in Section 6.8.2.1, the preferred Model IV from Table 6.4 in both levels and first difference form is estimated for the pre-restructuring period. Of course, with fewer observations, only a relatively small number of explanatory variables can be included in these models. In Section 6.8.2.2, counterfactual analysis is developed without considering the possibility that the values of some of the explanatory variables in the post-restructuring period may have been affected by restructuring. This additional feature is incorporated in Sections 6.8.2.3 - 6.8.2.5. Specifically, adjustments to the variables to remove the impact of restructuring is considered in Section 6.8.2.3, while counterfactual analysis using these values is reported in Section 6.8.2.4 for the levels model and in Section 6.8.2.5 for the model in first differences.

6.8.2.1 Modelling in the Pre-Restructuring Period

As mentioned earlier, because restructuring has also influenced several of the explanatory variables, a proper evaluation of the effect of restructuring on carbon emissions would require the removal of the impact of restructuring on such variables. However, obtaining values of carbon emissions in the absence of restructuring requires estimating the model differently, that is, rather than using a dummy variable to separate the pre- and post-restructuring periods, carbon emissions are modeled for the pre-restructuring period 1990 – 2000. Based on the results of this model, carbon emissions are forecasted for the post-restructuring period, 2001 – 2005. These forecast values provide counterfactual carbon emissions, that is, estimates of the amounts of carbon emissions that would have been observed had electricity market restructuring not been implemented. These counterfactual values of carbon emissions can then be compared with the actual values to determine the role of restructuring in lowering or raising carbon emissions.

The results from the estimated model (for the pre-restructuring period) in both levels (1990-2000) and differenced form, to account for unit roots in both the carbon emission and cratio variables (1991-2000), are presented in Table 6.9. The t-ratios for both models were determined based on autocorrelation consistent (Newey-West) covariance matrices because the presence of autocorrelation was detected in the earlier models and these two models are simply based on subsamples of the data used for estimation of the previous models.

The Ramsey RESET test results in Table 6.9 do not provide any indication of specification issues for either the levels model or the first-differenced model. Diagnostic tests for heteroskedasticity and autocorrelation yielded the results in Tables 6.10 and 6.11.

Table 6.9: Estimation Results for the Pre-Restructuring Period

Levels model		First differenced model	
cratio	7,891.8		
	1.32		
		ΔCratio	-2417**
			-5.79
renew	-14,677	**renew**	2183.3*
	-1.34		2.26
hratio	4,470.7†	**hratio**	-1507.3**
	2.52		-7.06
growth	250.81†	**growth**	720.28**
	2.33		13.86
T	1,569.8*	**T**	-231.76**
	2.88		-3.22
constant	159,600	**constant**	-21165*
	1.75		-1.99
DF	asymptotic	DF	asymptotic
R-Squared	0.9375	R-Squared	0.8989
DW	2.65	DW	2.65
JB normality p value	0.769	JB normality p value	0.779
Ramsey tests p values		Ramsey tests p values	
- with squared terms	0.099	2	0.477
- with cubed terms	0.291	3	0.622
- with terms to the power 4	0.367	4	0.87

Notes: 1. **, *, and † indicate significance at the 1%, 5%, and 10% levels, respectively.
2. Numbers below the respective coefficients are estimated t ratios.
3. In order to manage the coefficient on 'renew', the variable renew was multiplied by 100.

Table 6.10: Tests for Heteroskedasticity – Models for the Pre-Restructuring Period

Levels Model			First Differenced Model		
HET tests [Crit df=1, 3.84]	**BP**	**BPK**	**HET tests [Crit df=1, 3.84]**	**BP**	**BPK**
cratio	0.46	0.91	cdiff	1.65	1.08
renew	0.25	0.49	renew	0.55	0.36
hratio	1.20	2.35	hratio	1.4	0.91
growth	0.54	1.06	growth	3.68	2.4
t	0.20	0.39	t	1.97	1.29

Table 6.11: Tests for Autocorrelation – Models for the Pre-Restructuring Period

AUTO LM Test	Levels Model (OLS with autcov)	Differenced Model (OLS with autcov)	Critical Values
LM1	4.16	1.16	3.841
LM2	7.67	1.21	5.991
LM3	7.70	2.73	7.815
LM4	8.09	N/A	9.488

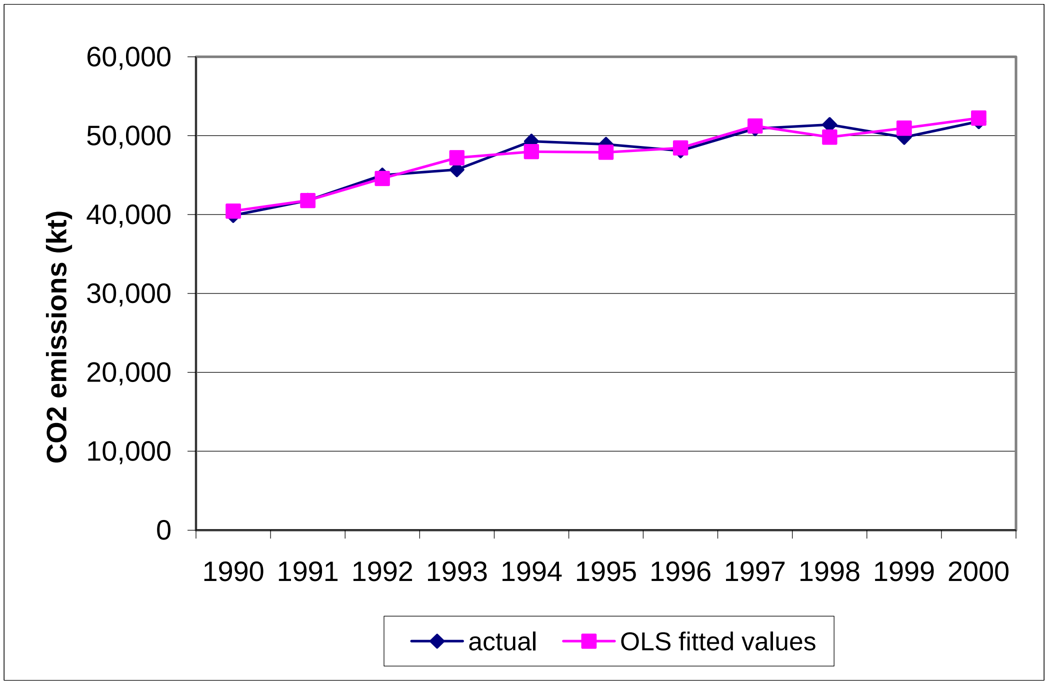
The BP and BPK test results in Table 6.9 do not indicate any evidence of heteroskedasticity. However, LM tests for autocorrelation, reported in Table 6.10, do indicate the presence of autocorrelation for the levels model. Of course, in the levels model, standard errors are based on autocorrelation consistent (Newey-West) covariance matrices. In view of the severe data limitations, and since our purpose here is primarily to obtain forecasts of carbon emissions, compare those forecasts with the actual carbon emission values and eventually to compare the finding with the result from the model with a dummy variable, no further analysis concerning autocorrelation and specification issues is undertaken, although this could be a useful extension once longer data series become available.

Notwithstanding the need for a longer data series, it is important to recall that any counterfactual carbon emissions obtained from the models in Table 6.9 would need to be viewed cautiously in view of concerns with these estimated models for the pre-restructuring period. As far as the levels model in Table 6.9 is concerned, only the variables **growth** and **Hratio** have coefficients that are statistically significant at the 10% level, with both having the expected signs, while the time trend T is statistically significant at the 5% level. Since other variables are statistically insignificant, and growth and **Hratio** are only statistically significant at the 10% level, it does not seem that the levels model has much explanatory power. The first differenced model, that takes account of non-stationarity, seems to have better explanatory power in that all coefficients are statistically significant at least at the 5% significance level. However, this explanatory power comes at the expense of having unexpected coefficient signs of the variables **ΔCratio, Renew and Hratio.** It is simply not intuitive to expect that an increase in coal based generation would decrease carbon emissions, or that an increase in renewable based capacity would increase emissions, or that a decrease in efficiency would reduce carbon emissions.

The first differenced model in Table 6.9 appears to be worse than the first differenced models in Columns 6 and 7 of Table 6.8 (estimated for the entire data period rather than just the pre-restructuring period) in that at least there the sign on the variable **Renew** was expected. Since the models in Table 6.8 were estimated using a longer data series, this appears to reaffirm the need to use a longer data series to estimate the model that is then used to obtain counterfactual carbon emissions.[14] In any event, any counterfactual carbon emissions for the post-restructuring period obtained using the estimated models reported in Table 6.9 must be viewed cautiously, and should be regarded only as preliminary estimates. While not a great deal of confidence can be placed on the specific results obtained from these models, they nevertheless illustrate the application of the methodology developed in Chapters 4 and 5 in the context of electricity prices to a different aspect of electricity market restructuring.

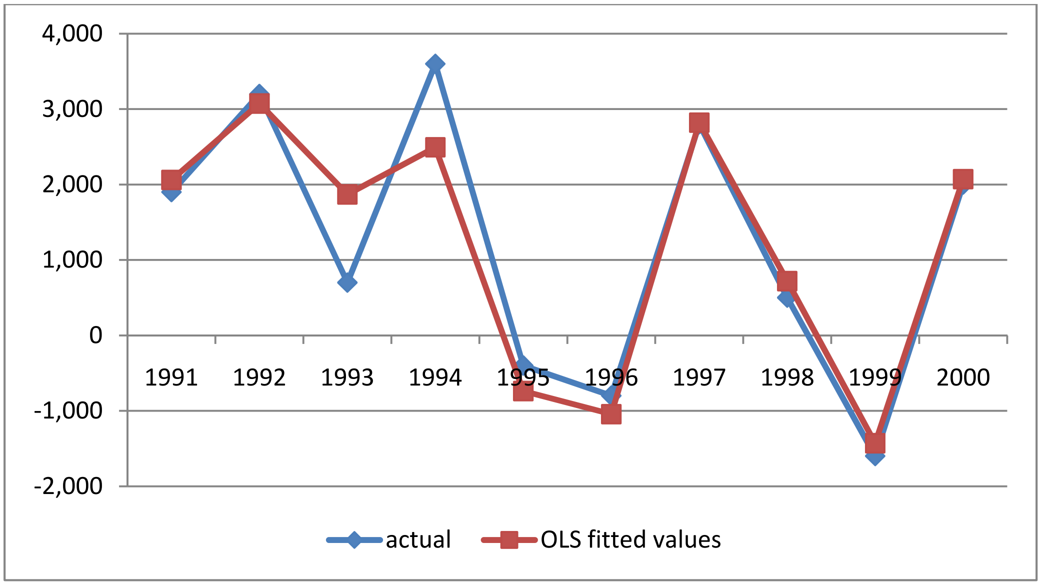
In Figures 6.7 and 6.8, actual carbon emission values (first differences in Figure 6.8) are plotted along with the fitted values for 1990 – 2000 to indicate how well the models fit the actual carbon emission and the first differenced carbon emission data, respectively. In both cases the fitted values are quite similar to the observed values, confirming the high R^2 values in Table 6.9.

Figure 6.7: Actual and Fitted Carbon Emissions, 1990-2000



[14] For future work, rather than forecasting carbon emissions it may be preferable to attempt to deal with non-stationarity issues by modelling – and forecasting for the post-restructuring period – either carbon emission intensity, defined as the ratio of carbon emissions to GDP, or the carbon emission rate, defined as the ratio of carbon emissions to generation. Since carbon emissions from electricity generation are usually not separately measured but are calculated on the basis of a formula, another potential avenue for future work could involve modelling and then forecasting the generation mix, and then inferring carbon emissions or emission intensity or the emission rate.

Figure 6.8: Actual and Fitted First Differenced Carbon Emissions, 1991-2000



6.8.2.2 Counterfactual Results without Adjusting the Values of the Explanatory Variables in the Post-Restructuring Period

Based on both the levels and first differenced models estimated from 1990 – 2000, carbon emission forecasts from 2001 – 2005 are tabulated in Table 6.12. The graphs of the actual values of carbon emissions and first differences of this series, along with the forecasted values for 2001 – 2005 and the 95% level confidence intervals (determined with 5 degrees of freedom) are presented in Figures 6.9 and 6.10, respectively.

Table 6.12: Actual and Predicted Values in the Post-Restructuring Period

Levels Model			First Differenced Model		
	actual	predicted		actual	predicted
2001	53,200	59,891	2001	1,400	-3,455
2002	52,700	68,921	2002	-500	-6,137
2003	54,500	53,539	2003	1,800	-3,066
2004	52,400	42,703	2004	-2,100	-958
2005	53,000	41,113	2005	600	-272

Figure 6.9: Actual and Forecast Post-Restructuring Period Carbon Emissions

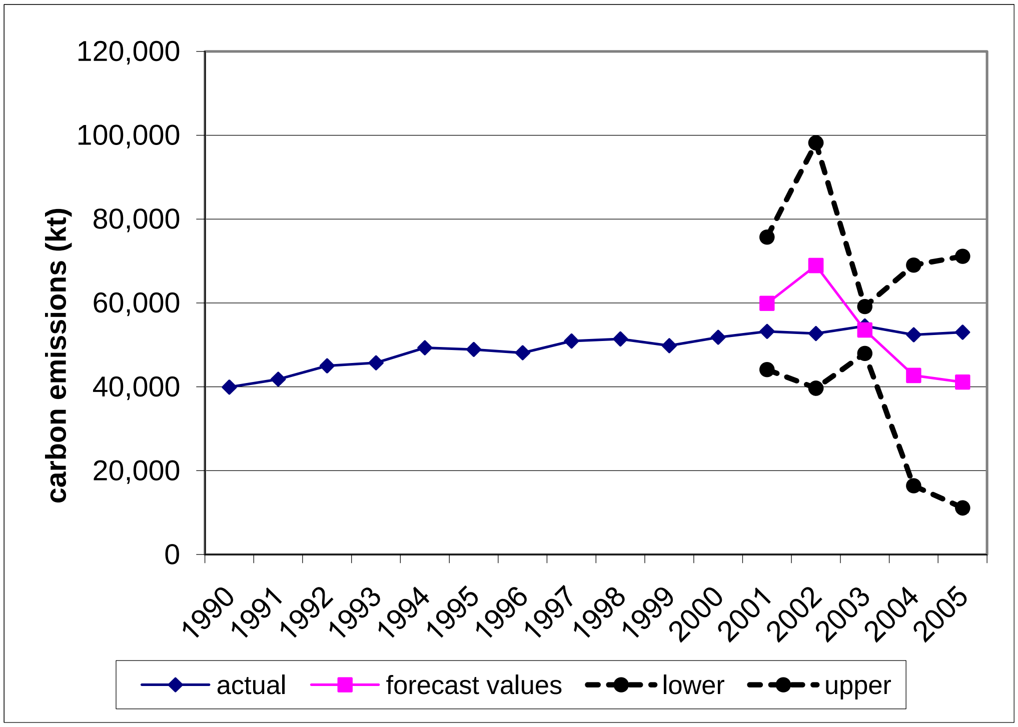
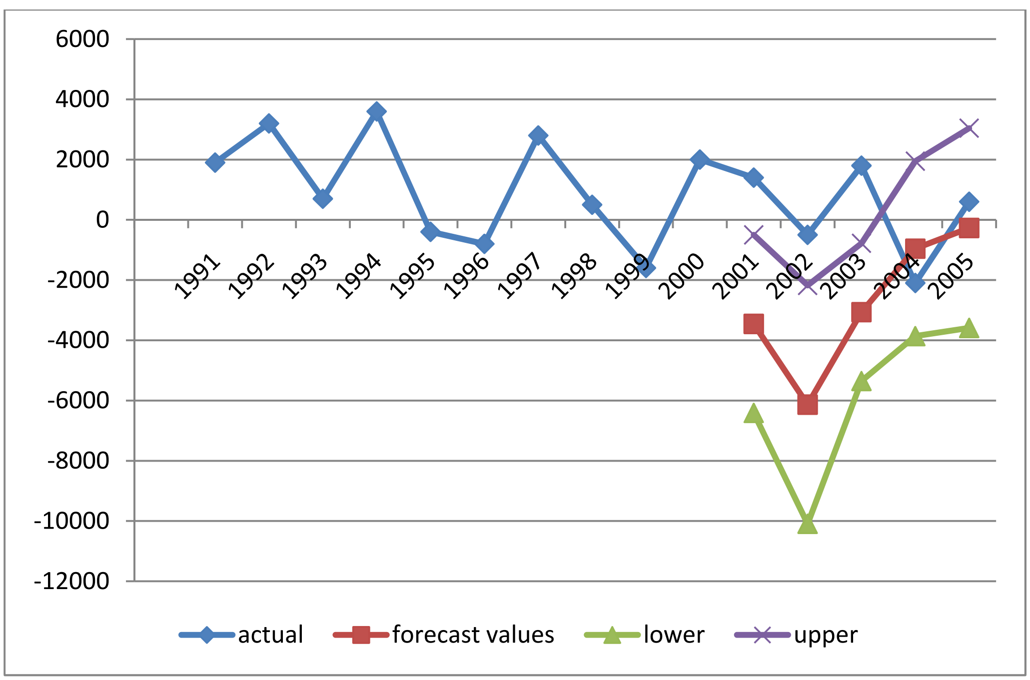


Figure 6.10: Actual and Forecast Post-Restructuring Period First Differenced Carbon Emissions



Forecasts from the levels models indicate that, having controlled for capacity mix, efficiency, electricity demand, renewable capacity and technological development, in the post restructuring period for the first two years carbon emissions declined, since forecast values exceed actual values. However, from 2003 – 2005 carbon emissions have increased (forecast values are below actual values) due to electricity market restructuring. Since the 95% confidence interval around the forecast value includes the actual value in all years, it is not possible from the levels model to conclude that restructuring had any significant effect on carbon emissions.

In contrast, as can be seen from Figure 6.10, the forecasts from the first-differenced model lie below the actual values in all post-restructuring years except 2004. Thus, in these years, changes in carbon emissions appear to have increased due to electricity market restructuring. Further, for 2001-2003, the 95% confidence interval around the forecast value does not include the actual value, so that restructuring can be viewed as having significantly increased carbon emission changes in these years. In subsequent years, the upper bound of the 95% confidence interval exceeds the actual values, so that no statistically significant effect of restructuring on carbon emission changes can be detected in these last two years.

6.8.2.3 Removing the Impact of Restructuring from the Post-Restructuring Values of the Explanatory Variables

Determination of the effect of restructuring on the relevant explanatory variables in the post-restructuring period in the model of carbon emissions, and modification of the values of these variables to remove these effects, utilizes a similar approach as in Chapter 5 in the context of the model of electricity prices. Since the entire procedure of matching a restructured and non-restructured US jurisdiction and determining the difference in differences is essentially the same as undertaken in the context of electricity prices, details are suppressed. Rather, only a brief outline and results are provided below.

Based on an analysis of US data, non-restructured jurisdictions that best matched each of the 19 restructured jurisdictions for which data were available were identified. The jurisdictions were matched on the basis of the generation-capacity mix, the fuel price, and electricity demand variables, as well as renewable based electricity capacity, since this ‘renew’ capacity variable is used in the estimation of the model for carbon emissions. The method of matching jurisdictions on the basis of renewable capacity is the same as in the context of the other three variables, that is, computing absolute differences between the renewable capacity values of each of the restructured jurisdiction with the respective values in the 27 non-restructured jurisdictions. The overall matching procedure results in three[15] or four non-restructured jurisdictions being paired

[15] Visual inspection of the jurisdiction matching table indicates that for some restructured states, there are only three unique matching un-restructured jurisdictions.

with each of the 19 restructured jurisdictions based on the four variables – renewable capacity, generation-capacity mix, fuel price, and electricity demand. These various pairings are shown in Table 6.13.

Table 6.13: Matching Restructured and Non-Restructured Jurisdictions

Restructured Jurisdiction	Matching Non-Restructured Jurisdiction			
	Capacity & generation	HDD & Real GDP growth	Fuel price	Renewable Capacity
Arizona	Florida	Georgia	Indiana	Colorado
Arkansas	Nebraska	Tennessee	Missouri	Georgia
Delaware	Nebraska	Missouri	Florida	Kansas
Illinois	Florida	Indiana	Louisiana	Louisiana
Maryland	Nebraska	Kansas	Alabama	Kentucky
Massachusetts	Louisiana	Kansas	Florida	Colorado
Michigan	Kansas	Indiana	Tennessee	N. Carolina
Montana	Nebraska	Wisconsin	Nebraska	Vermont
Nevada	Kansas	Georgia	Tennessee	Tennessee
New Hampshire	S. Carolina	Vermont	S. Carolina	N. Carolina
New Jersey	Louisiana	Kansas	Florida	Minnesota
New Mexico	Colorado	Tennessee	Louisiana	Iowa
New York	Louisiana	Kansas	Florida	Colorado
Ohio	N. Dakota	Indiana	Minnesota	W. Virginia
Oklahoma	Nebraska	Alabama	Iowa	Missouri
Oregon	Washington	Utah	Kansas	Washington
Pennsylvania	Nebraska	W. Virginia	Alabama	Wisconsin
Texas	Florida	Florida	Minnesota	W. Virginia
Virginia	Florida	Kansas	Florida	Tennessee

Once these jurisdictions are matched up, difference-in-differences (*d-i-d*) values are computed to determine the impact of restructuring on carbon emissions. The first step in the difference in differences method is to compute the difference between the average pre-restructuring value and the average post-restructuring value for each jurisdiction for each of the 3 endogenous variables included in the model for Alberta – **cratio**, **hratio**, and **renew**. Technically, the differences were computed for 5 variables, since **cratio** and **hratio** are based on coal- and natural gas-based capacity and coal- and natural gas-based heat rates, respectively.

Next, for each three or four pairs of jurisdictions – the jurisdiction in the 1st column and the jurisdiction from the corresponding row in each of the next four columns in Table 6.13 (some of which may be the same) – the difference between these differences is computed, again for each of the 5 endogenous variables.

The three or four *d-i-d* values for each of the 19 restructured jurisdictions are aggregated in order to yield at most 76 *d-i-d* values. These 76 *d-i-d* values were added to the actual values of the 5 endogenous variables for each of the 5 post restructuring years 2001 – 2005. In this way, any outlying and technically infeasible counterfactual values of the 5 endogenous variables could be eliminated from the subsequent analysis. Identification of outlying and infeasible counterfactual values is also the reason why the *d-i-d* computations were determined for 5 endogenous variables as opposed to the 3 endogenous variables that are actually present as explanatory variables in the estimated models.

Thus, while at most 76 counterfactual values are expected for each of the 5 endogenous variables for each of the 5 post restructuring years from 2001 – 2005, fewer than 76 values remain for natural gas capacity, coal- and natural gas-based heat rates, and renewable capacity once outlying and infeasible counterfactual values have been eliminated. The actual numbers of counterfactual values for each of the 5 endogenous variables for each of the post restructuring years from 2001 – 2005 are shown in Table 6.14.

Table 6.14: Number of Counterfactual Values for each Explanatory Variable

Endogenous Variable	2001	2002	2003	2004	2005
Coal based capacity	76	76	76	76	76
Natural gas based capacity	73	73	73	73	73
Coal based heat rate	67	67	67	67	67
Natural gas based heat rate	53	31	25	33	51
Renewable Capacity	48	47	50	51	51

These sets of at most 76 values are each treated as if they were drawn from a specific distribution, and an attempt is made to identify the underlying distribution that generated those 76 or fewer counterfactual values for each of the post restructuring years from 2001 - 2005. This is done using the Crystal Ball software (an add-on to Microsoft Excel), which chooses among a variety of distributions – such as normal, gamma, beta, t, etc. – using three goodness of fit statistics – the Anderson-Darling (AD), Chi-square (Chi-sq), and Kolmogorov-Smirnov (KS) statistics (Decisioneering, Inc., 2004:154). The 75 distributions (one for each of the 5 endogenous variables for each of the 5 years in the post restructuring period for each of the three tests) are reported in Table 6.15.

Table 6.15: Best Fitting Distributions for Each Endogenous Explanatory Variable

Distribution fitting test	Coal-based Capacity				
	2001	2002	2003	2004	2005
AD	max extreme	max extreme	max extreme	max extreme	max extreme
Chi sq	beta	beta	beta	beta	beta
KS	max extreme	max extreme	max extreme	max extreme	max extreme
	Natural gas-based Capacity				
	2001	2002	2003	2004	2005
AD	max extreme	max extreme	max extreme	max extreme	max extreme
Chi sq	max extreme	max extreme	max extreme	max extreme	max extreme
KS	max extreme	max extreme	max extreme	max extreme	max extreme
	Coal-based Heat rates				
	2001	2002	2003	2004	2005
AD	triangular	triangular	triangular	triangular	triangular
Chi sq	beta	beta	beta	beta	beta
KS	triangular	triangular	triangular	triangular	triangular
	Natural gas-based Heat Rate				
	2001	2002	2003	2004	2005
AD	gamma	triangular	beta	triangular	beta
Chi sq	beta	gamma	min extreme	gamma	triangular
KS	beta	beta	beta	beta	triangular
	Renewable based Capacity				
	2001	2002	2003	2004	2005
AD	max extreme	max extreme	logistic	logistic	logistic
Chi sq	max extreme	normal	weibull	max extreme	max extreme
KS	max extreme	max extreme	logistic	logistic	logistic

6.8.2.4 Counterfactual Results based on the Levels Model

Crystal Ball computes the three test statistics for all the possible distributions for each endogenous variable for each year. Distributions are selected based on the lowest value of each of three test statistics. Since the Anderson Darling test is widely used in fitting distributions (Decisioneering Inc, 2004), the distributions identified through the criterion of the lowest Anderson Darling statistic are selected. Using a Monte Carlo simulation process, a particular value is selected from the specified distribution for each endogenous explanatory variable, and these values are then used in the estimated model from the pre-restructuring period (1990-2000) to obtain counterfactual carbon emission forecasts for each year of the post-restructuring period. This process is repeated many times, thereby yielding a whole array of counterfactual carbon emissions in the post-restructuring period from 2001 – 2005 as summarized in Table 6.16.

Table 6.16: Comparison of Counterfactual and Actual Results – Levels Model

Post restructuring year (1)	Actual Carbon emissions (2)	Mean of Carbon emission forecasts (3)	Mean based on distribution (4)	% emission forecasts < actual carbon emission (5)	Distribution fitted on emission forecasts (6)
2001	53,200	59,632	59,639	29.32%	min extreme
2002	52,700	65,904	65,714	18.36%	min extreme
2003	54,500	53,363	53,313	51.65%	logistic
2004	52,400	44,261	44,216	69.00%	logistic
2005	53,000	43,211	43,267	71.54%	logistic

Column (3) of Table 6.16 indicates that the mean of the distribution of carbon emission forecasts – that is, of the counterfactual values of carbon emissions – obtained through the simulation process described above, is higher than the actual carbon emission values for the first two years in the post restructuring period, that is, 2001 and 2002. This indicates that in these two years, carbon emissions would have been higher had electricity market restructuring not occurred. However, for each of the post restructuring years from 2003 – 2005, the mean counterfactual carbon emission values are lower than the actual carbon emission values, indicating that carbon emissions would have been lower had electricity market restructuring not taken place. When distributions were fit on the set of carbon emission forecasts that were obtained via the simulation process, the mean carbon emission values that were obtained from these distributions, shown in column (4) of Table 6.16, supported the result derived on the basis of the mean values of carbon emission forecasts in Column (3) of Table 6.16. According to the values in Column (5) of Table 6.16, 51% or more of the counterfactual carbon emission values were lower than the actual carbon emission values in all years after 2002, supporting the claim that carbon emission would have been lower for the 2003 – 2005 period had electricity market restructuring not taken place.

6.8.2.5 Counterfactual Results based on the First-Differenced Model

The effect of restructuring on carbon emissions can also be evaluated by comparing actual and counterfactual carbon emission values obtained using the first differenced model, which accounts for non-stationarity in the carbon emission and cratio variables. As with the levels model, the 76 or fewer aggregated counterfactual values, determined on the basis of the five different composite variables, were used. The distributions of the counterfactual values of the explanatory variables are the same as those determined in the case of the levels model. The slight difference in the context of the first-differenced model is that counterfactual values of coal- and natural gas-based capacity for the year 2000 were also used, in order to eventually obtain counterfactual values of the first differenced ‘cdiff’ variable from 2001 – 2005. The results from the simulation analysis are shown in Table 6.17.

Table 6.17: Comparison of Counterfactual and Actual Results – First Differenced Model

Post restructuring year (1)	Actual First differenced Carbon emission (2)	Mean of First differenced Carbon emission forecasts (3)	Mean based on distribution (4)	% emission forecasts < actual carbon emission (5)	Distribution fitted on emission forecasts (6)
2001	1400	-10,339	-3,846	79.98%	logistic
2002	-500	14,221	-5,291	78.05%	logistic
2003	1800	2,026	-3,307	79.25%	logistic
2004	-2100	3,625	-599	41.91%	logistic
2005	600	-258	-258	57.79%	student's t

The results from the first-differenced model indicate that the mean of the distribution of the counterfactual electricity price differences is centered below the actual carbon emission difference for the post-restructuring period only in 2001 and 2005. When distributions were fit on the counterfactual carbon emission difference forecasts, the mean based on the distribution, shown in Column (4), is centred below the actual carbon emission difference in all years except for 2004. These results indicate that counterfactual changes in carbon emissions would have been lower in the post-electricity market restructuring period if restructuring had not occurred.

Since it is difficult to know how counterfactual changes in carbon emissions being below actual changes in carbon emissions relates to the relationship between counterfactual and actual levels of carbon emissions, in Table 6.18 the counterfactual changes in emissions have been added in sequence to the 2000 level of carbon emissions to obtain a post-restructuring series of levels of counterfactual carbon emissions based on the first-differenced model.

Table 6.18: Comparison of Actual Carbon Emissions with Counterfactual Carbon Emission levels based on the First Differenced Model

year	actual	forecast based on first diff.	
2000	***51,800***	**mean**	**distribution mean**
2001	53,200	41,461	47,954
2002	52,700	55,682	42,663
2003	54,500	57,708	39,356
2004	52,400	61,333	38,757
2005	53,000	61,075	38,499

The results in Table 6.18 indicate that the mean forecast of the level of carbon emissions from the first-differenced model is below the actual level only in 2001, suggesting that except for this year, carbon emissions are lower with restructuring than they would have been otherwise. However, the results in the final column are strikingly different, indicating that carbon emissions with restructuring are higher in all post-restructuring years than they would have been otherwise.

A visual inspection of the distribution of forecasts reveals that *Crystal Ball* is fitting distributions over very large ranges, for instance, for 2004, the distribution is fit from -2 million to 2 million. This would suggest that numbers based on column (3) of Table 6.17 are likely to be more credible than numbers based on column (4) of the same table. While Column (3) of Table 6.17 indicates that the changes in carbon emissions would have been lower for 2001 and 2005 under continued regulation, Table 6.18 indicates that the level of carbon emissions would only have been lower in 2001.

Taken overall, the results from the simulations based on both the levels model as well as the first differenced model lead to different conclusions. While the results based on the levels model indicate that carbon emissions would have been lower for 2003-2005 under continued regulation, the results based on the first differenced model yield the same result for only 2001, although changes in carbon emissions would have been lower in both 2001 and 2005. These results need to be viewed cautiously however, as noted earlier, since the estimated models in Table 6.9 that are used to generate the counterfactual carbon emissions either do not have much explanatory power (the levels model) or have unexpected signs on the coefficients (first differenced model). Further, since natural gas-based generation increased post restructuring (Figure 6.4) and the share of renewable based generation has also increased since 2002 (Figure 6.3), carbon emissions would have been expected to be higher under continued regulation, a result which would have been consistent with Pomorski (2006). Thus, rather than focusing on the specific results reported here, which are best viewed as being preliminary, or at least indicative of the type of results that can be obtained using this method, the emphasis is better placed on the methodology that is used to determine these counterfactual carbon emissions, a methodology that accounts for the issue of endogeneity, which has been neglected in the very few studies that have investigated the impact of restructuring on carbon emissions.

6.9 Summary and Conclusion

Since restructuring of electricity markets is not necessarily – or at least not solely – directed at lowering the cost of providing electricity, this chapter has focused on evaluating the impact of the electricity market restructuring in Alberta on another metric, that is, carbon emissions. Just as in the context of electricity prices, there appear to be two main viewpoints on the impact of restructuring on carbon emissions. On the one hand there is a view that by instituting competition, restructuring would contribute toward innovative ways of minimizing environmental damage from pollution and might therefore be expected to reduce carbon emissions from the power sector. On the other hand, it could be argued that by contributing toward incentives to produce electricity as cheaply as possible, and in view of Alberta's relatively abundant and cheap coal supplies, electricity market restructuring could make it less likely that carbon emission reductions would occur with restructuring.

The analysis in this chapter has been directed towards evaluating which of these two views is more applicable to Alberta. Specifically, the issue that is addressed is the determination of the extent to which carbon emission reductions have occurred or are likely to occur as a result of electricity market restructuring in Alberta. Just as in the context of electricity prices, the focus has been on determining what carbon emissions would likely have been in the post-restructuring period if restructuring had not occurred, and then comparing these so called "counterfactual" carbon emissions to the actual carbon emissions that were observed in this period. If these counterfactual carbon emissions are higher than observed carbon emissions, it would suggest that restructuring did help to keep carbon emissions lower than they would otherwise have been. However, if the counterfactual carbon emissions are lower than the actual carbon emissions, this would indicate that the effect of restructuring – in terms of carbon emissions – was to make carbon emissions higher.

Since the methodology for constructing counterfactual values that is used here in the context of carbon emissions was developed and applied in Chapters 4 and 5 in the context of electricity prices, the analysis in this chapter can be viewed as an application of the framework developed in the previous chapters. First a structural model of the determinants of carbon emissions was built and, in view of the limited number of observations available for estimation, estimated over the entire time period 1990-2005 with a dummy variable that equaled one in the restructuring period. Key variables included in the structural model of the determinants of carbon emissions included variables that captured the generation mix, efficiency, the electricity price, electricity demand, and green power. Variants of the preferred model were estimated to account for non-stationarity and autocorrelation. Having controlled for capacity mix, efficiency, electricity demand, renewable capacity, and technological development, and accounting for non-stationarity in the results presented in Table 6.8, the positive coefficient on the restructuring period dummy variable in these models indicates that electricity price restructuring seems to have increased carbon emissions.

Next, similar to the approach in Chapter 4, the model (without the dummy variable) was estimated just for the 1990-2000 pre-restructuring period, and using actual values of the explanatory variables in the post-restructuring period, forecasts using this model – counterfactual values of carbon emissions – were obtained for 2001-2005. Based on a comparison of counterfactual and actual carbon emissions in this latter period, we find that, having controlled for capacity mix, efficiency, electricity demand, renewable capacity and technological development, for the first two years of the post restructuring period carbon emissions declined because of electricity market restructuring, but from 2003 – 2005 carbon emissions increased. However, forecasts (counterfactual values) from the first-differenced model lie below the actual values of changes in carbon emissions in all post-restructuring years except 2004. Thus, the results in these years indicate that changes in carbon emissions have increased due to electricity market restructuring, although based on confidence interval analysis, these results are not statistically significant for the levels model and are statistically significant only for 2001-2003 for the first difference model.

While the results from both types of models, the one estimated for 1990-2005 and the other estimated from 1990-2000, indicate that restructuring may have contributed toward an increase in carbon emissions, these models do not take account of the possibility that some explanatory variables – specifically, those capturing capacity mix and heat rates – may themselves have been affected by restructuring. If this is the case, the values of these endogenous explanatory variables in the post-restructuring period need to be adjusted to account for this impact before carbon emissions are forecasted. In order to account for this endogeneity, the methodology developed in Chapter 5 in the context of electricity prices was applied to carbon emissions. Restructured and non-restructured US jurisdictions were matched with each other, and the difference in differences (*d-i-d*) was calculated. The entire procedure was essentially the same as in Chapter 5 except that here, *d-i-d* values were also computed using renewable based capacity. Eventually, treating the values of the endogenous variables in the structural model as if they were drawn from a distribution, Monte Carlo simulations were conducted using *Crystal Ball* to yield a distribution of forecasted carbon emissions. Based on the levels model shown in Table 6.16, Column (5), 51% or more of the counterfactual carbon emission values were found to be lower than the actual carbon emission values, for each year in the 2003 – 2005 period, providing some support to the claim that carbon emission would have been lower for this period under continued regulation. However, the results from the first-differenced model, which accounts for non-stationarity, reported in Tables 6.17 and 6.18, indicate that the mean of the distribution of the counterfactual electricity price differences is centered below the actual carbon emission difference for only

2001 and 2005, or possibly just 2001 based on the values in the third columns of these two tables. Effectively, the results from the simulations based on both the levels model as well as the first differenced model, do not support strong conclusions concerning the effect of electricity market restructuring on carbon emissions, since the results appear to be quite sensitive to the model used for simulation. Nevertheless, it appears that at least for some years in the post-restructuring period, carbon emissions might have been lower under continued regulation. A contributing factor to these weaker results, in contrast to those found for electricity prices in Chapters 4 and 5, might be the limited number of observations available for estimation, and the limitations that this placed on adequately modelling carbon emissions, or the annual changes in these emissions, in the pre-restructuring period, as well as on conducting sensitivity analyses.

As noted earlier, these results need to be viewed cautiously since the estimated models reported in Table 6.9 that were used to generate the counterfactual carbon emissions either do not have much explanatory power (the levels model) or have unexpected signs on several of the coefficients (first differenced model). Another issue that underlies these counterfactual carbon emissions is that natural gas-based generation increased post restructuring (Chapter 4 and Figure 6.4), and the share of renewable based generation has increased as well since 2002 (Figure 6.3), so that on this basis carbon emissions would have been expected to be higher under continued regulation, a result which would also have been consistent with Pomorski (2006). Thus, rather than focusing on the specific results reported here, which are best viewed as being preliminary, or at least indicative of the type of results that can be obtained using this method, the emphasis is better placed on the methodology that is used to determine these counterfactual carbon emissions, a methodology that accounts for the issue of endogeneity, which has been neglected in the very few studies that have investigated the impact of restructuring on carbon emissions. Use of a longer data series, or perhaps supplementing the analysis with a detailed power plant level data set, might usefully enhance future examinations of this issue.

In conclusion, the analysis in this chapter adds to the policy debate on carbon emission mitigation in that by identifying the determinants of CO2 emissions and modelling their effects, it provides a framework that may help facilitate the making of more informed decisions on climate change mitigation. Specifically, given the issues encountered in terms of unexpected signs of the coefficients of the explanatory variables or the poor explanatory power of the models, it was observed that perhaps rather than forecasting carbon emissions, a more relevant focus may be on carbon emission intensity, defined as the ratio of carbon emissions to GDP, or the carbon emission rate, defined as the ratio of carbon emissions to generation. Moreover, since carbon emissions for electricity generation are typically not separately measured, but are calculated on the basis of a formula, this may account – at least in part – for the counterintuitive signs on some of the explanatory variables in the model. For this reason it may be better to model, and subsequently forecast, the generation mix rather than carbon emissions per se, and to infer carbon emissions forecasts from the resulting generation mix forecasts. These remain as issues for future research, which would benefit from a longer time series data set.

Another important contribution of Chapter 6 is that the regression framework that is developed is consistent with allowing restructuring to impact carbon emissions through various complex channels. For instance, it was noted in Section 6.4 how the impact of restructuring on carbon emissions through its effects on the generation mix could be negative, based on the extent to which restructuring induces natural gas-based rather than coal-based generation, or positive, based on real-time pricing and enhanced long-distance electricity trade that shifts the generation mix from natural gas to coal. In addition, the model and estimation methodology that is utilized in this chapter, which specifically takes into account endogeneity, helps to clearly delineate the impact of restructuring on carbon emissions by first accounting for the impact of restructuring on endogenous explanatory variables such as the generation mix.

Moreover, the analysis in this chapter contributes to the literature by modelling carbon emissions in a different framework than the predominant ones, which are the Environmental Kuznets Curve framework or simulation studies, as explained in Section 6.3. Above all, it shows how the framework developed in the previous chapters can be applied to assess the impact of electricity market restructuring through a metric other than electricity prices, which in the analysis here is carbon emissions.

Chapter 7: Summary, Conclusions, and Future Work

7.1. Summary and Conclusions

When electricity restructuring initiatives were introduced in Alberta, it was argued that the changes would deliver lower electricity prices to residential consumers than would otherwise be the case. These restructuring initiatives were finalized with the institution of retail electricity market competition in 2001. Although residential electricity prices in Edmonton, Alberta, were among the lowest in Canadian cities prior to this time, residential electricity prices in Alberta increased dramatically in 2001, immediately following the last stage of the restructuring. Residential electricity prices in Alberta have never returned to their pre-restructuring levels – let alone been lower than their pre-2001 values – and although inflation has meant that prices have increased everywhere, Edmonton, when ranked on the basis of electricity prices alongside other Canadian cities, remains at a similar rank in 2010 as it had been at in 1998. Proponents of restructuring argue that electricity prices would have been even higher had restructuring not been pursued, citing the role of drastically higher natural gas prices and other variables. However, Alberta residential electricity consumers appear to remain unconvinced, tending to attribute their higher electricity prices to factors such as market power and manipulation associated with the restructured Alberta electricity market.

Such attribution might indeed be justified, but it is not appropriate to simply compare prices before and after restructuring to determine the effects of such a significant change in market structure. In particular, values of many other variables also changed during this period, and these changes may, at least partially, account for the electricity price changes that were observed. Separating the impact of restructuring on residential electricity prices from the effects of changes in other variables is best achieved through a structural model of the determinants of residential electricity prices. Such a model for Alberta was developed in Chapter 4 to assess the extent to which changes in residential electricity prices in Alberta following restructuring could be attributed directly to the restructuring that occurred. The basic framework used in Chapter 4 involved formulating and estimating a structural model of the determinants of electricity prices in Alberta in the period prior to restructuring.

As far as the Alberta electricity market is concerned, the only other study to have determined counterfactual electricity prices is Wellenius and Adamson (2003). However, their study is couched in a cost of service framework that requires information on the various cost inputs for the post-restructuring period, which is unlikely to be available. Moreover, the validity of using those cost inputs for electricity price forecasting is questionable, since cost inputs already have the effect of restructuring captured within them so that it could be somewhat misleading to employ them to find counterfactual electricity prices. Other studies pertaining to Alberta electricity prices are not concerned with estimating a structural model, but instead model the spot electricity price, that is, they focus at the wholesale level rather than at the retail level. For example, both Atkins and Chen (2002) and Xiong (2004) deal with mean reverting, time varying, jump diffusion models of Alberta spot electricity prices, while Hinich and Serletis (2006) focus on signal coherence spectral analysis of Alberta hourly spot prices.

The determinants of Alberta electricity prices were based not only on the identification of the key variables implied in the cost of service approach but also augmented by other variables determined through a review of the literature. The model developed in Chapter 4 is similar in approach to four studies in the US – Fagan (2005), Taber, Chapman and Mount (2005), Joskow (2006) and CERA (2005) – in that these studies also aim at constructing counterfactual electricity prices through regression analysis. In contrast to the models developed in these four studies, however, issues like sample selection bias and accounting for stranded costs are not relevant for the model in Chapter 4. More importantly, the model in Chapter 4 aims to account for many variables that have only been selectively used in the four respective studies, namely capacity variables, heat rates, generation variables, capacity constraint variables, fuel prices, weighted fuel prices, demand variables and cost of capital.

This approach used in Chapter 4 essentially involved formulating and estimating a structural model of the determinants of electricity prices in Alberta in the period prior to restructuring. This estimated model was used with observed values of the relevant variables in the post-restructuring period to forecast electricity prices that would have been expected to be observed in this latter period in the absence of restructuring. A comparison of the forecast electricity prices from this counterfactual analysis with the prices actually observed in the post-restructuring period was used to assess the effects of restructuring on residential electricity prices. The model was estimated for the pre-restructuring period from 1965 onwards due to data limitations and in order to avoid structural breaks. Also, since the effects of the restructuring process began to surface in 1998, even though retail competition was not actually introduced until 2001, the pre-restructuring period model was initially estimated using annual data for the period 1965 to 1997, although sensitivity analysis with respect to the end point was used to ascertain the importance of this choice.

Annual predictions made for the period 1998-2005 based on the model estimated using data from 1965-1997 indicated that the predicted prices exceed the actual prices for the years 1998-2005. However, this result started to change when the model was estimated using slightly different sample periods, from 1965-1998, 1965-1999 and 1965-2000, with predictions being made in each case for subsequent years. Thus, the results are sensitive to the estimation period. Since retail prices remained regulated until the beginning of 2001, in terms of evaluating the effect of restructuring, the main focus is on 2001, the year that retail restructuring took effect, and the ensuing years. On this basis of the model estimated from 1965–2000, it appeared that retail prices did increase as a result of restructuring, although this increase appeared to have been reversed in 2005.

Sensitivity analysis of the model also included allowing for a time trend to control for technological progress and dealing with potential simultaneity bias due to variables such as capacity and generation that could proxy for electricity demand. The counterfactual (post-restructuring predicted) electricity prices based on an estimated model that included a time trend are generally similar to those obtained previously. Hausman tests failed to reject the null hypothesis of the absence of endogeneity due to coal-based capacity, natural gas-based capacity, the share of coal-based generation, and this coal share multiplied by the coal price, both in models that did and did not account for possible autocorrelation. On this basis, no further analysis of this endogeneity question was undertaken, although it may be a fruitful area for further research.

To account for non-stationarity, all the variables except growth, heating degree-days, coal-based heat rates and the interest rate were first differenced and the model was re-estimated. Using this model, alternatively estimated using data for 1966 to 1997 and 1966 to 2000, predictions of electricity price were obtained to 2005. The forecasts based on the model estimated from 1966 – 1997 tend to be higher than actual values, although the forecasts based on the model estimated from 1966 – 2000 tend to be lower than actual values, suggesting that retail prices did increase as a result of restructuring. In view of the poorer fit of the difference model in the pre-restructuring period, it is not possible to ascertain the extent to which these prediction errors are due to the poor fit of the model or to restructuring of the electricity industry. Nevertheless, the differenced model estimated for 1966-2000 tends to support the conclusions reached using the model where the variables were in levels form.

One drawback of the results in Chapter 4 was that once non-stationarity was accounted for, the signs on all statistically significant estimates were as expected except for the economic growth variable. The unexpected sign on this variable casts some uncertainty on the counterfactual prices in the post-restructuring period that were computed based on the estimated model. However, given that the model was developed carefully based on mimicking a COS approach and through a relevant review of the literature, it is likely that any improvement in obtaining the counterfactual electricity prices would most likely arise from use of a longer data set, or perhaps by accessing a detailed plant-level data set which, while beyond the scope of this thesis, might be considered for future work. Regardless, the counterfactual electricity prices obtained here appear to be preferable to those, found in the existing literature, that are not based on a comprehensive structural model of the determinants of the electricity price.

The regression analysis in Chapter 4 was conducted under the assumption that, post restructuring, the explanatory variables remained exogenous. However, to the extent that restructuring of electricity markets is undertaken because these markets are not functioning optimally, or as desired, it would be expected that there would be a number of changes that occur directly as a result of the restructuring. As such, in evaluating the effects of restructuring on electricity prices it is necessary to separately account for changes in variables that could be viewed as occurring due to the restructuring from those changes that would have been likely to occur anyway. In terms of the regression model, it is important to control for these effects so as to clearly delineate the effect of restructuring on electricity prices. This analysis was undertaken in Chapter 5, which augmented the model in Chapter 4 through simulations to account for the potential endogeneity of several explanatory variables. It may be noted that while a few studies use a regression framework to construct counterfactual electricity prices, none of these other studies actually account for the endogeneity issue.

In Chapter 5, other Canadian and US jurisdictions were examined to determine if the values of the explanatory variables in Alberta in the post-restructuring period could be replaced with values from one of these other non-restructured jurisdictions. As an alternative, restructured and non-restructured US jurisdictions were compared to determine the likely effect of electricity industry restructuring on the explanatory variables, with a view to modifying the observed values of these variables in Alberta in the post-restructuring period to adjust for these effects. After removing the potential impact of restructuring from the actual post-restructuring Alberta values of the explanatory variables through the difference in differences approach, new sets of counter-factual electricity prices were constructed and compared with the prices that were actually observed in Alberta in the post-restructuring period. These new sets of counterfactual electricity prices are viewed as an improvement on the counterfactual electricity prices based on the naïve approach used in Chapter 4.

Two approaches to augmenting the Chapter 4 model were considered in Chapter 5. In the first, other jurisdictions were examined to identify one non-restructured and one restructured jurisdiction that most closely matched Alberta's electricity generation and consumption environment. Then, for Alberta and the other restructured jurisdiction, the averages of each of the relevant potentially endogenous explanatory variables were determined in the pre- and post-restructuring periods for that jurisdiction. Next, for each variable in each jurisdiction, the difference between these averages in the two periods is calculated. The same procedure is followed twice for the non-restructured jurisdiction, first using the two periods defined for Alberta, and second using the two periods defined for the other restructured jurisdiction. Finally, the difference for Alberta is subtracted from the difference for the matching periods in the non-restructured jurisdiction and the difference for the other restructured jurisdiction is subtracted from the difference for the matching periods in the non-restructured jurisdiction. The resulting two sets of numbers, so-called difference in differences, *d-i-d*, provide alternative measures of the impact of restructuring on each of the endogenous variables used in the electricity price model of Chapter 4. Each set of *d-i-d* figures is added to the actual values of the endogenous variables for Alberta for 2001 – 2005 to obtain the counterfactual values of these variables in the post restructuring period in Alberta. This in turn yielded two sets of counterfactual electricity prices for Alberta for this period.

Based on the analysis in Chapter 5, Texas and Kansas were identified as the regulated and non-regulated jurisdictions, respectively, that best match Alberta. The *d-i-d* values, based on Alberta/Kansas and Texas/Kansas comparisons, were added to the actual values of the endogenous variables for Alberta for each year of the 2001 to 2005 period to obtain two sets of counterfactual electricity prices. When compared to the results obtained in Chapter 4, where the endogeneity of the explanatory variables in the post-restructuring period was ignored, the results based on the Texas/Kansas computations confirm the conclusion that electricity prices in Alberta would have been lower in the absence of restructuring for 2001-2004. However, based on the Alberta/Kansas computations, the opposite result was obtained for the entire 2001–2005 period excluding 2002. Sensitivity of the counterfactual electricity price results was evaluated by alternatively using the parameter estimates from the levels model estimated until 1997, which accounted for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring, and the first-differenced model, estimated for 1966 to 2000, which accounted for non-stationarity of some of the variables. Sensitivity of the counterfactual electricity price results was also evaluated by using *d-i-d* figures based on jurisdiction correspondences other than Kansas and Texas.

Overall, the sensitivity analysis confirmed the original findings, namely that the counterfactual Alberta electricity prices were below the actual Alberta electricity prices, although this result was much clearer with the difference model, and only applied for adjustments based on some jurisdiction pairings, and mainly in 2002 (for the post-restructuring period) using the levels model estimated for the period ending three years prior to restructuring. In addition, for the original levels model, estimated to 2000, the results are mixed depending on the particular jurisdiction pairings that are used, although the counterfactual prices are less than the actual prices in 2002 and 2003 in almost all cases. Although it is to be expected that different model specifications will yield somewhat different results, both the original results and those obtained as part of the sensitivity analysis make it difficult to reach a definitive conclusion about the effect of restructuring in Alberta on electricity prices.

One of the issues with the first approach used in Chapter 5 is that it is difficult to know which pairing of jurisdictions should be used to obtain the *d-i-d* values and hence know which of the counterfactual values of the endogenous variables is most appropriate, as a number of compromises had to be made in order to determine the best matching jurisdiction. Moreover, a second limitation of this approach is that it involved a single adjustment to each endogenous variable that is the same in each year of the post-restructuring period. To overcome these limitations, a different approach was used, based on a distribution of adjustments to values of explanatory variables that was determined from the *d-i-d* values obtained for a variety of different US restructured/non-restructured jurisdiction matches. With this approach, the endogenous variables were treated as having values based on underlying distributions, and this allowed – via simulation analysis – the determination of a distribution for the counterfactual electricity prices for each of the post restructuring years in Alberta. Based on this simulation analysis, the mean of the counterfactual electricity prices was found to be lower than the actual electricity price for each of the post restructuring years from 2001–2004, but excluding 2005. Moreover, the result that 70% or more of the counterfactual electricity prices were lower than the actual electricity prices for 2001 – 2004 lent strong support to the claim that electricity prices would have been lower for the 2001–2004 period had electricity market restructuring not taken place in Alberta.

Sensitivity of the distribution of counterfactual electricity price results was evaluated by treating the counterfactual values of the explanatory variables as having emanated from three separate underlying distributions, based on the three composite variables (generation and capacity, fuel prices and electricity demand), for each of the post-restructuring years from 2001–2005 as opposed to assuming that the counterfactual values of the explanatory variables emerged from a single distribution. The results appeared robust to this sensitivity analysis as well as to a sensitivity analysis that was conducted by alternatively using the parameter estimates from the levels model estimated until 1997, which accounted for the possibility that restructuring expectations affected behaviour in the years immediately prior to restructuring. In fact, the results from the levels model estimated until 1997 yielded a stronger result than the base case, in that the mean of the distribution of the counterfactual electricity prices is centred below the actual electricity price for the entire post restructuring period from 1998–2005. Likewise, a sensitivity analysis based on the first differenced model, which accounts for the possible non-stationarity of some of the variables, yielded stronger results compared to the base case in that the mean of the distribution of the counterfactual electricity price differences is centred below the actual electricity price difference for the entire post restructuring period from 2001-2005. Effectively, the results from the various simulations support the finding that post-restructuring electricity prices in Alberta have been higher relative to what they would have been had electricity market restructuring not been pursued.

Apart from Taber et al (2005), three of the four US based studies– Fagan (2005), Joskow (2006) and CERA (2005) – that determined counterfactual electricity prices through regression analysis, conclude that electricity market restructuring has lowered electricity prices. These three studies that have employed an econometric framework are part of the twelve studies conducted in the US context, as reviewed by Kwoka (2006), nine of which conclude that restructuring has either led to retail price benefits or brought about cost efficiencies. Blumsack et al (2008) also note, as does Kwoka (2006), that while studies conducted by the industry and consultants report price savings from restructuring, studies conducted by academics do not find any evidence on the connection between lower electricity prices and electricity market restructuring. Even in more recent studies, contrasting results are reported. Carlson and Loomis (2008), focusing on one specific jurisdiction, conclude that Illinois consumers have benefitted from restructuring based on counterfactual electricity price changes determined by controlling for fuel price changes and capacity expansions. However, Showalter (2008), focusing on various US jurisdictions, concludes that electricity prices have increased in restructured states based on the counterfactual electricity price trend in restructured states determined on the basis of the trends in electricity prices in non-restructured states. The model developed in Chapter 4 is more comprehensive than many of the models used in the literature and, augmented by the novel simulation approach developed in Chapter 5, effectively lends more strength to the result in contrast to that found by the three econometric and six non-econometric studies reviewed by Kwoka (2006).

The findings from Chapters 4 and 5 actually are parallel to those referenced by Blumsack et al (2008). For instance, Blumsack et al (2008) reference Zarkinau and Whitworth (2006) and Zarkinau et al (2007) to indicate that retail electricity prices for both residential and commercial consumers have increased in those areas in Texas where retail competition has been instituted. Likewise, they reference Taber et al (2006) who, on the basis of estimating a Generalized Autoregressive Conditional Heteroskedasticity GARCH model for four classes of US electricity prices – residential commercial, industrial and overall average prices –from 1990 – 2004, and using utility level data, conclude that there does not seem to be evidence that electricity market restructuring has led to lower retail electricity prices. Finally, notwithstanding the improvements that might be expected from use of a detailed plant-level data set, the counterfactual electricity prices obtained in Chapters 4 and 5 do appear to be an improvement over those in the existing literature that are not based on a comprehensive structural model of electricity prices and/or that fail to account for various endogeneity issues.

Since restructuring of electricity markets is not necessarily – or at least not solely – directed at lowering the cost of providing electricity, Chapter 6 in this thesis is concerned with another aspect of the effects of electricity market restructuring in Alberta. Specifically, the focus here is on evaluating the impact of electricity market restructuring on carbon emissions. According to one view, as espoused by Thierer (1997), competition would contribute toward innovative ways of minimizing environmental damage from pollution, and as such electricity market restructuring might therefore be expected to reduce carbon emissions from the power sector. However, it could be argued that with electricity market restructuring, the incentive for firms is to produce electricity as cheaply as possible, and in view of Alberta’s relatively abundant and cheap coal supplies, this could make it less likely that carbon emission reductions would occur with restructuring. Thus, the focus of Chapter 6 is to evaluate which of these two views is more applicable to Alberta. Specifically, the issue that is addressed is the determination of the extent to which carbon emission reductions have occurred or are likely to occur as a result of electricity market restructuring in Alberta.

Of course, with increased general concern about greenhouse gas (GHG) emissions, any observed reduction in CO_2 emissions subsequent to restructuring in Alberta cannot be automatically attributed to the effects of restructuring itself. Rather, it is necessary to determine what might have been expected to occur had restructuring not taken place, and then assess whether what is actually observed involves less than this amount of CO_2 emissions. Thus, the methodology that is used has similar features to the methodology used to examine whether electricity prices for residential consumers decreased as a result of electricity market restructuring, as considered in Chapters 4 and 5.

As for the model of electricity prices, the explanatory variables included in the model for carbon emissions are determined through a review of the literature. Four variants of the model for carbon emissions were estimated for 1990 – 2005, in view of data availability limitations, with a dummy variable included to distinguish between the pre and post restructuring periods. However, the dummy variable was statistically insignificant for all four models. Based on diagnostic tests, one of the models was further adjusted to account for non-stationarity issues by estimating a first differenced version. This yielded a significantly positive coefficient on the dummy variable, leading to the conclusion that restructuring has seemingly led to an increase in carbon emissions. However, the unexpected signs on some of the explanatory variables, even after accounting for non-stationarity, indicate that counterfactual carbon emissions obtained from these models would need to be viewed cautiously.

As noted in Chapter 4, because restructuring has also influenced several of the explanatory variables, a proper evaluation of the effect of restructuring on carbon emissions would require the removal of the impact of restructuring on such variables. This essentially necessitated estimating the carbon emissions model for the pre restructuring period 1990 – 2000 and using the estimated coefficients to forecast carbon emissions for the post restructuring period 2001 – 2005. These forecast values reflected values of counterfactual carbon emissions, that is, values of carbon emissions had electricity market restructuring not been implemented. These counterfactual values of carbon emissions were then compared with the actual values to determine the role of restructuring in lowering or raising carbon emissions. Forecasts from the levels model indicate that having controlled for capacity mix, efficiency, electricity demand, renewable capacity and technological development, in the post restructuring period for the first two years carbon emissions declined, however, from 2003 – 2005 carbon emissions increased due to electricity market restructuring. However, forecasts (counterfactual values) from the first-differenced model lie below the actual values of changes in carbon emissions in all post-restructuring years except 2004. Thus, the results for these years point towards the possibility that changes in carbon emissions have increased due to electricity market restructuring.

However, based on confidence interval analysis, these results are not statistically significant for the levels model and are statistically significant only for 2001-2003 for the first difference model.

Finally, the methodology developed in Chapter 5 was applied to the carbon emissions model to account for the potential endogeneity of some of the explanatory variables. Based on the levels model, the mean of the distribution of carbon emission forecasts – the counterfactual values of carbon emissions obtained through simulations – was found to be higher than the actual carbon emission values for the first two years in the post restructuring period, that is, 2001 and 2002. After 2002, for each of the post restructuring years from 2003 – 2005, the mean counterfactual carbon emission values were lower than the actual carbon emission values suggesting that carbon emissions would have been lower had electricity market restructuring not been instituted. Based on the first-differenced model, the mean of the distribution of the counterfactual changes in carbon emissions was found to be centered below the actual carbon emission difference only for 2001 and 2005, implying that the counterfactual level of carbon emissions was below the actual level just for 2001. Effectively, the results from the simulations based on both the levels model as well as the first differenced model, do not support strong conclusions concerning the effect of electricity market restructuring on carbon emissions, since the results appear to be quite sensitive to the model used for simulation. Nevertheless, it appears that at least for some years in the post-restructuring period, carbon emissions might have been lower under continued regulation. A contributing factor to these weaker results, in contrast to those found for electricity prices in Chapters 4 and 5, might be the limited number of observations available for estimation, and the limitations that this placed on adequately modelling carbon emissions, or the annual changes in these emissions, in the pre-restructuring period, as well as on conducting sensitivity analyses.

As was noted, these results need to be viewed somewhat cautiously since the estimated models that were used to generate the counterfactual carbon emissions either do not have much explanatory power (the levels model) or have unexpected signs on several of the coefficients (first differenced model). Another issue that underlies these counterfactual carbon emissions is that natural gas-based generation increased post restructuring, while the share of renewable-based generation has also increased since 2002, so that on this basis carbon emissions would have been expected to be higher under continued regulation. Thus, rather than focusing on the specific results that were obtained, which are best viewed as being preliminary, or at least indicative of the type of results that can be obtained using this method, the emphasis is better placed on the methodology that is used to determine these counterfactual carbon emissions, a methodology that accounts for the issue of endogeneity, which has been neglected in the very few studies that have investigated the impact of restructuring on carbon emissions.

In conclusion, on the basis of the findings in Chapters 4 and 5, it appears that residential electricity prices in Alberta would have been lower in the absence of electricity market restructuring, although the results in Chapter 6 are not so clear concerning carbon emissions. Of course, it has been argued that the benefits of electricity market restructuring would be realized in the long run as opposed to the short run, which suggests that more data might be required before reaching definitive conclusions. Even apart from this consideration, policy analysis suggests that there are alternative frameworks for electricity market restructuring that might better help achieve the goal of lower electricity prices. Based on a review of select literature, suggestions include coupling restructuring initiatives with the institution of long-term contracts between utilities and plant owners, forward contracts, average based pricing, real-time pricing, and government loan guarantees to ensure that issues of electricity price fluctuations, market power and the resulting high electricity prices can be curbed. In terms of instituting retail choice, lessons can also be drawn from successful electricity market restructuring initiatives, for instance, the Texan model is considered to be most successful because it includes the separation of retail supply from the distribution segment to create a level playing for retail competitors and to encourage retail competition (Joskow, 2005). Likewise, the UK model appears a good choice for ensuring sufficient generation capacity and curbing electricity price fluctuations because power pool prices are based on the inclusion of a capacity charge element to the system marginal price and generators and suppliers are allowed to enter into long term fixed price contracts (Yajima, 1997).

Alternatively, incentive based regulation or re-regulation, can also be considered to meet the goal of achieving lower electricity prices. Irrespective of the motivation for re-regulation, moving from a restructured market to a regulated one raises the issue of asset valuation. Lave et al. (2007b) suggest that a gradual approach toward re-regulation may involve bringing the costs of the newer power plants into the rate base and terminating the power pool market with the retirement of the older power plants. Thus, alternative models of restructuring, or alternative options like re-regulation or variants of incentive based regulation – profit sharing, using yardsticks and performance incentives – could all be considered as potential solutions to the over-investment issues raised by rate of return regulation and the market power and electricity price fluctuations raised by restructuring. As such, for any jurisdiction, including Alberta, achieving lower electricity prices may not necessarily be a product of a black or white decision between regulation and restructuring, but the discourse could potentially involve many possible alternatives.

7.2. Future Work

Since Blumsack et al (2008), like Kwoka (2006), attribute the conflicting evidence reported in the literature to the issues in the definition of restructuring, the failure to account for price caps, and the use of aggregated data, future work could revolve around addressing some of these critiques by accessing firm level data and incorporating price caps in the analysis. Apart from addressing the critiques of Kwoka (2006), since the interest rate was used as a proxy for the cost of capital, future work could also include obtaining a better cost of capital data series. The analysis could also be conducted on electricity prices extracted from consumer power bills from Edmonton and Calgary as opposed to using the data series from the Statistics Canada Electric Power Statistics source.

If electricity prices are extracted from power bills to residential consumers for further work, then many issues arise, including the separation of the transmission and distribution charges components which (in part) constitute a flat rate as opposed to the generation charge component that varies due to fluctuations in the whole sale power pool market. One possibility is to focus merely on the generation component of the electricity prices as that has been directly affected by restructuring, whereas the transmission and distribution segments have remained regulated. Another justification for such an approach could be that generation constitutes a huge proportion of the electricity bill as compared to the transmission and distribution segments. In the US context, for instance, transmission and distribution constitute 40% of the electricity bill (Rosen et al., 2007), whereas generation costs account for 54% - 69% of the total costs of generating electricity (Yajima, Chapter 4, 1997). However, this is contradicted by Fagan (2006), who states that generation accounts for only 30% of the total electricity price faced by consumers. While such contradictory information needs resolution, given the Alberta context, another consideration would be the computation of average electricity prices by using a simple or weighted average of electricity prices found from Edmonton and Calgary to proxy for electricity prices in Alberta. It may be noted that in the context of the US, averaging by using electricity consumption as weights has been ignored in favour of the relatively easier simpler averages (US General Accounting Office GAO, 2002).

In Chapter 5 of this dissertation, Alberta data were modified on the basis of the analysis of data pertaining to both restructured and un-restructured US jurisdictions, since no single non-restructured US jurisdiction could be found that mimicked the Alberta electricity market in significant respects. The analysis conducted was comprehensive in the sense that all 51 jurisdictions were considered. The jurisdictions were paired together – one restructured and one non-restructured – on the basis of simple correlations and absolute differences between the values of various electricity market variables. Future work could include the use of cluster analysis to pair up jurisdictions as opposed to using correlation and absolute difference computations.

Another avenue for future work could include sub-samples of the 51 jurisdictions based on certain characteristics. This would then provide alternative set of results on the counterfactual electricity prices in Alberta, which could then be compared with those determined on the basis of the comprehensive analysis that used all 51 jurisdictions. One possibility is to focus only on jurisdictions that generate most of their electricity from coal – Colorado, Indiana, Iowa, Kentucky, New Mexico, Nevada, Ohio, West Virginia and Wyoming – or alternatively on jurisdictions that generate most of their electricity from natural gas – Texas, Oklahoma and Louisiana (US DOE, 2000). Another possibility is to focus on jurisdictions that have included Renewable Portfolio Standard proposals as part of their restructuring legislation – Connecticut, Maine and Massachusetts (Burtraw et al., 2002).

Yet another possibility is to distinguish restructured jurisdictions on the basis of the competitive model that was introduced in that jurisdiction, and to compare counterfactual electricity prices based on these two types of jurisdictions. For example, the Independent Retailer Model, in which residential customers are expected to look for retailers, has been adopted in Texas and Pennsylvania, whereas the Wholesale Club Model, in which the distribution company acts as the retailer for the pooled residential customers, has been adopted in New Jersey and Maine (Fagan, 2006).

Finally, in the context of carbon emissions, given the issues encountered in terms of unexpected signs of the coefficients of the explanatory variables or the poor explanatory power of the models, perhaps rather than focusing on carbon emissions, either carbon emission intensity – defined as the ratio of carbon emissions to GDP – or the carbon emission rate – defined as the ratio of carbon emissions to generation – might be more relevant for future work. Moreover, since carbon emissions from electricity generation are typically not separately measured, but are calculated on the basis of various formulas, this may in part explain some of the counterintuitive signs obtained on the estimated coefficients for the explanatory variables in the model. This suggests that it might be useful to focus on modelling the generation mix rather than carbon emissions per se. With such an approach, counterfactual values for the generation mix could be obtained in the post-restructuring period, and these could be used to infer counterfactual carbon emissions. Whatever the approaches that are used, future analysis will undoubtedly benefit from longer data series, and might also be improved by assembling a detailed plant-level data set that could be used in the modelling and estimation of electricity prices and carbon emissions, and in subsequently obtaining counterfactual values for these variables.

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