AMPCO

August 26, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Hydro One Networks Inc.
Change to Electricity Transmission Revenue Requirement and Rates
Submission of AMPCO Evidence
Board File No. EB-2010-0002

Pursuant to the Board's Procedural Order No. 2 dated July 21, 2010, attached please find AMPCO's evidence in the above proceeding.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely yours,

(ORIGINAL SIGNED BY)

Adam White
Association of Major Power Consumers in Ontario

Copies to: Hydro One Networks Inc. (via email)
Intervenors (via email)

Association of Major Power Consumers in Ontario
www.ampco.org

372 Bay Street, Suite 1702
Toronto, Ontario M5H 2W9

P. 416-260-0280
F. 416-260-0442

Potential efficiencies from improving transmission rate design in Ontario

Submissions to the Ontario Energy Board

OEB File No. EB-2010-0002

Association of Major Power Consumers in Ontario

August 26 2010

1 Outline of Submission

2 Summary of Submission

This submission introduces a substantive update of AMPCO's previous submissions[1]and elaborates the arguments for changing the design of the network charge determinant.

In addition to presenting new and updated analysis, based on new and updated data, the submission describes a framework for analysis of some potential impacts of the proposed change: the costs and benefits, the level of load shift, transmission cost shifts, the impact on commodity cost, and the impacts on transmission customers.

3 The Network Charge Determinant

3.1 The status quo

The current Network Charge Determinant is arrived at by calculating a monthly average of total costs allocated to the network assets divided by customers' forecast demand during monthly system peaks.

The Network Charge Determinant currently is based on the greater of a customer's monthly coincident peak or 85% of his non-coincident peak demand during working weekdays. As it is currently designed, the combination of monthly coincident peak and the 85% non-coincident peak "ratchet" obscures efficient price signals to customers: (1) to reduce consumption during periods of peak demand and high costs, and (2) to increase consumption during periods when demand and costs are low.

3.2 Principles of rate design

AMPCO proposes a new 'critical peak' design that would be based on a customer's demand during the five highest hours of the five highest demand days in a year.

---

[1] The design of the current rates were first approved by the OEB pursuant to an application by Hydro One Networks Inc. in 1999 (RP-1999-0044). The rates were updated (but not the design) based on a cost-of-service application in 2006 (EB-2006-0501). AMPCO made detailed submissions on potential efficiencies for improving transmission rate design before the Ontario Energy Board (OEB File No. EB-2008-0272) in January 2009.

AMPCO's proposal to allocate networks costs to customers on the basis of peak demand contribution is consistent with two related basic propositions: (i) that the design of network charges should reinforce the tendency on the HOEP to produce a price signal that reflects the scarcity value of electricity; that peak electricity is more expensive than off peak electricity and should therefore cost more; and (ii) that consumers should be incented to shift their electricity consumption from peak to off-peak periods. The current method of recovering network costs on the basis of monthly peaks but with the 85% ratchet is inconsistent with these propositions and undermines the price signals (i.e., HOEP) that do exist.

AMPCO's proposal is also consistent with two basic principles of public utility economics: (i) that capacity prices should be borne by consumers on the basis of their contribution to peak demand; and (ii) that minimizing inefficiency is best achieved by raising prices in inverse proportion to demand elasticities.

With respect to (i), Alfred E. Kahn expresses the principle as follows:[2]

"The economic principle here is absolutely clear: if the same type of capacity serves all users, capacity costs *as such* should be levied only on utilization at the peak. Every purchaser at that time makes its proportionate contribution in the long-run to the incurrence of those capacity costs and should therefore have the responsibility reflected in its price."

Further, as Arthur Lewis is quoted by Bonbright, "… no amount of correction can alter the fact that standing costs of the undertaking are related not to the maximum rate at which the individual consumer takes, but to the amount he takes at the time of the station peak."[3]

---

[2]Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions*, Vol. 1 (MIT Press, 1998), at p. 89.

[3] Lewis, W. Arthur, 1949. *Overhead costs: Some essays in economic analysis*. New York. Reinhart, at page 52. As quoted in Bonbright, James C. et al. 1988. *Principles of Public Utility Rates. Second Edition*. Public Utilities Reports, Inc. Arlington Virginia.

Principle (ii) is an expression of "Ramsey Pricing"[4], which has been described as follows:

"The Ramsey pricing 'rule' that gives the prices that minimize the deadweight losses is to raise prices in inverse proportion to demand elasticities."[5] Ramsey pricing results in efficiency because it leads to less overall demand reduction for the same cost. As a result, it leads to more net production. In simple terms this means higher productivity, more investment, higher employment, lower inflation, higher incomes and increased tax revenues to governments.

Recovering network costs on the basis of demand during periods of peak demand is consistent with Ramsey pricing because, by definition, those customers who are most sensitive to increases in price, and are capable of adjusting their demand in response to price, will end up paying less than they otherwise would. The proposal therefore systematically incorporates demand elasticity.

Finally, the rate design proposed by AMPCO, coincident with the statutory objectives of the Ontario Energy Board, is intended:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the

[4] Frank Ramsey. *A Contribution to the Theory of Taxation*. Economic Journal, March 1927.

[5] Viscusi, Vernon and Harrington, *Economics of Regulation and Antitrust,* (3d) (MIT Press, 2000), at 352.

timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.[6]

3.3 The proposed rate design

AMPCO proposes that a customer's monthly transmission demand charges be determined on the basis of the average of that customer's coincident peak demand on the highest hour on each of the 5 highest peak days of demand in Ontario in the previous 12-month period.

Ideally, the 12 month period would commence in July and culminate in June. This is because, under normal weather circumstances, Ontario will experience its highest peak demands during hot summer days. Having these peak days occur at the beginning of the baseline period reduces the risk and cost associated with the uncertainty that would be created if the baseline period were to start, for example, in January, when relative peaks may occur, but absolute peaks are unlikely.

In the proposed design, therefore, network charges in a 12-month period, for example commencing July 1 2011, would be based on peak demand in the previous 12-month period, calculated as follows:

Equation 1

$$\begin{aligned}&\mathit{Network\ Charge\ Determinant\ in}\ 2011\\&=\frac{\mathit{Network\ Revenue\ Requirement\ July}\ 2011-\mathit{June}\ 2010}{\sum(\mathit{Average\ Customer\ Demand\ During}\ 5\ \mathit{Peak\ Periods\ July}\ \ 2010-\mathit{June}\ 2011)}\end{aligned}$$

Because nobody knows exactly when peaks will occur, the proposed rate design offers the advantage of placing the challenge of predicting these periods, and the risks and rewards in doing so, solely on customers. Those customers who see value in, and can profit by, reducing their demand during peak periods will invest in the capability to do so, thereby creating a competitive advantage for themselves while promoting more efficient demand

[6] Ontario Energy Board Act, 1998, Section 1(1): Board objectives, electricity.

management and greater efficiency in the electricity system overall. These efficiencies will be enjoyed by all customers, through lower prices and reduced costs.

4 A framework for analysis

As we have noted, the statutory objectives of the Ontario Energy Board include the promotion of efficiency and efficient demand management. A proper evaluation of the likely efficiency impacts of any change, including the change we propose to the design of the network charge determinant, requires a review of the costs and potential benefits that would result from such a change.

Economic theory and established rate-making principles suggest that changing the network charge determinant so that it more closely resembles the long run marginal cost of network transmission service, that is allocated to customers based on their contribution to the system peak, is likely to promote more efficient demand management, by inducing customers to consume less when the costs of electricity are highest, and to consume more when the costs are lowest. These induced changes in demand are also likely to promote efficiency in generation, transmission, distribution, etc. by flattening the system load shape, reducing losses and congestion attributable to peak demand, increasing asset utilization and so on.

The Board directed Hydro One, in its Decision with Reasons in EB-2008-0272, to analyze AMPCO's rate design proposal and come forward with a suitable proposal for implementation for the Board's consideration. Power Advisory LLC (Power Advisory) was engaged by Hydro One to perform this work and was specifically asked to analyze the costs and benefits of implementing AMPCO's rate design. It is our assessment that a comprehensive analysis of these impacts was not undertaken by Power Advisory. Such analysis is beyond AMPCO's capabilities in this proceeding given current resource levels, data available to AMPCO and time constraints. In the alternative, we have undertaken additional research illustrating methodologies that we believe would be useful to the Board. They will assist the Board to analyze these impacts; they enumerate and describe categories of costs and benefits, a proper analysis of which would provide a reliable evidentiary basis on which the Board could decide to change the charge determinant.[7]

5 Costs

Costs associated with making a change in the design of the network charge determinant include costs to implement the change and ongoing costs associated with industrial demand management activities.

5.1 Implementation costs

Implementation costs would include:

- Changes to IESO settlement systems
- Changes, if any, to LDC settlement systems
- Investments in equipment, facilities, software and staff training by customers

The IESO indicates it expects its costs to be between $50,000 and $100,000 depending on the complexity of the design.[8]

Since the proposed change affects how the IESO settles bills for LDCs, but does not directly affect how LDCs settle bills for LDC customers, LDC costs of implementing the proposed design are not expected to be material.[9]

---

[7]The Independent Electricity System Operator ("IESO") recently conducted an economic analysis of the impacts on key measures of proposed changes in the design of the Global Adjustment payment amount. These measures included impact on system peak demand, total consumption, market price (HOEP) and average unit cost (HOEP + GA). Although the results were positive, differences in the context and starting point for change mean that the estimated impacts may not be directly transferable to the current proceeding. The theoretical basis for the IESO's findings, and the methods it employs, however, are applicable to the proposal before the Board. The IESO's work is described in two slide presentations, from October 2009 (http://ieso.ca/imoweb/pubs/consult/sac/sac-20091028-Item_7-Electricity_Pricing.pdf) and March 2010 (http://ieso.ca/imoweb/pubs/consult/sac/sac-20100331-Allocation-of-Global-Adjustment.pdf).

[8]Exhibit I, Tab 4, Schedule 63, Page 30, response (c).

[9] Reforming network charge determinants for LDC customers so that they (a) conform to the design of the network transmission charge determinant approved by the Board for transmission customers, and (b) promote efficiency and efficient demand management, would, however, require investments and expenditures by LDCs to modernize settlement systems,

Implementation costs for customers will vary. Some industrial customers already have relatively sophisticated energy management systems in place, and have established operating procedures and trained staff. For these customers, and in light of anticipated changes in the allocation of the Global Adjustment, we would not expect transmission-connected industrial customers to incur significant implementation costs.

5.2 Demand management costs

Ongoing costs to actually change demand in response to the change in transmission rate design will vary from firm to firm. Each firm faces different circumstances, involving the design and operation of its production process, the training and capabilities of its employees, the importance of electricity as a factor of production, the sensitivity of firm profitability to changes in electricity costs, and the firm's general financial well-being, as well as external factors related to the market for its products, prevailing product prices, competitive factors, and committed orders, etc.

A comprehensive evaluation of these costs, across the Ontario economy, should be part of a proper cost/benefit analysis. This evaluation is beyond AMPCO's current capabilities given resource, data and time constraints. In lieu of this, AMPCO intends to adduce testimony from representatives of leading industrial customers representing key economic sectors to describe the kinds of measures they might consider in response to a decision by the Board to change the design of the network charge determinant.

6 Benefits

Our research indicates that changing the design of the network charge determinant would create a number of benefits.

---

and might also require expenditures by some customers to update meters and acquire or develop appropriate energy management tools. These issues are important, but beyond the scope of the current proceeding.

6.1 Demand response and peak-shifting

From an efficiency, or total welfare perspective, the key benefit expected in response to implementation of a more efficient price signal, is more efficient consumption behaviour. In this case, the objectives of the change are to reduce demand during peak times, by attributing the long run marginal costs of network services to consumption during peak times.

Dr. Sen's report (Attachment 1) sets out a valid methodology for estimating how industrial customers will respond to changes in price, based on publicly available data and consistent with economic theory.

Dr. Sen's analysis reaffirms the basic propositions:

1. That industrial customers will reduce demand during peak periods in response to higher prices in peak periods; and furthermore
2. That industrial customers will consume more in off-peak periods in response to higher prices in peak periods.

The first effect speaks to how industrial customers respond to a change in price in real time. In economic terms this is referred to as the own-price elasticity of demand, i.e., the estimated change in demand during on-peak hours in response to a change in price in the same on-peak hours. The second effect addresses how industrial customers respond to a change in price in the previous period, i.e., the lagged price.

6.2 Reduced market prices

Dr. Sen's report also sets out a valid methodology for estimating the effects of changes in industrial demand on market prices, i.e., the prices paid by all customers. The methodology uses publicly available data and does not rely on complicated proprietary market simulation models. Dr. Sen's analysis confirms the propositions:

1. That industrial demand response during peak periods causes peak prices to be lower for all customers; and furthermore

2. That the subsequent industrial demand increase during off-peak periods causes prices to rise, but by a lesser amount than the reduction during peak periods.

Taken together, these findings suggest overall that customers, from the perspective of market prices, should be better off as a result of the proposed change. Customers whose consumption takes place more during peak periods, i.e., residential, should benefit most.[10]

6.3 Reduced Global Adjustment amounts

Electricity generators in Ontario that participate in the wholesale electricity market are paid the Hourly Ontario Energy Price ("the HOEP") for each megawatt hour produced. Customers pay the HOEP based on each megawatt hour consumed. Many generators also receive payments based on contracts with the Ontario Power Authority or regulated rates approved by the Ontario Energy Board. Customers are charged these additional costs via the "Global Adjustment", for wholesale customers including distribution companies, or the "Provincial Benefit" for customers of distribution companies. The Global Adjustment and Provincial Benefit currently are charged to customers based on each customer's total consumption during a month.

For some contracted and regulated generation, it is reasonable to assume that the Global Adjustment ("GA") operates like a contract-for-differences; as the HOEP goes up, the GA goes down; as the HOEP goes down, the GA goes up. This is more or less how GA varies in relation to HOEP, for example, with respect to the payment amounts for OPG's prescribed assets, the Bruce Power contracts[11], the non-utility generator contracts, and the renewable generation contracts entered into by the OPA. These generators, generally speaking, receive a fixed payment for each MWh they produce, the difference between that payment and the HOEP goes into the monthly GA payment amount.

---

[10] Whether a customer connected to a distributor can in fact benefit depends on the distribution customer class into which they fall and the design of rates for which they are eligible. Since distribution company customer classifications, rate designs and rates vary considerably, one cannot be assured that an efficient transmission rate design,once transformed by a distributor, will induce or reward efficient demand management by distribution customers whatsoever.

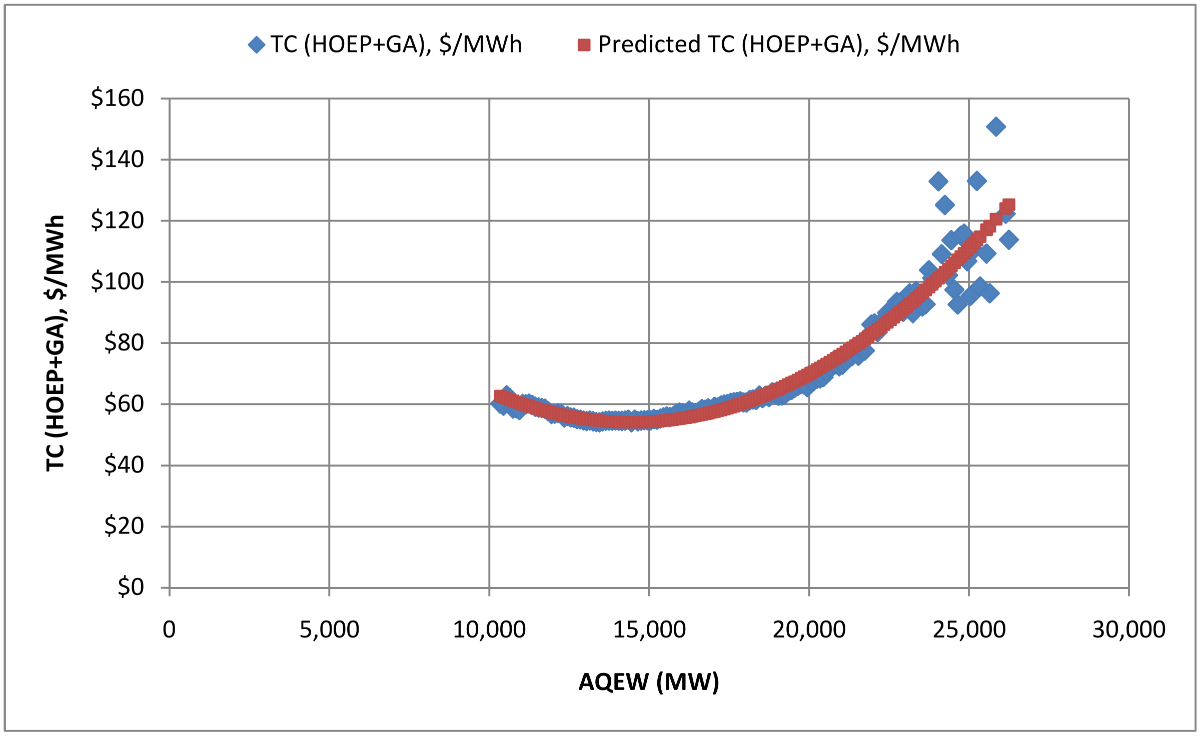
[11] The Bruce Power contracts vary between Bruce 'A' and Bruce 'B', are complicated, and the details are not public. We presume, however, that the contracts establish a floor price (but no cap) for power generated by Bruce Power.

However, this is not how GA varies in relation to HOEP during periods of low demand and low price, or in periods of high demand and high price. In low demand and price periods, the structure of the Clean Energy Supply contracts entered into by the OPA and gas-fired generators (in which generators are paid on the basis of monthly revenue requirements net of imputed market revenues) means that when these generators are deemed not to be earning market revenues, the monthly revenue requirement goes into the GA payment amount. This means that these generators are paid even when they produce nothing. Since this occurs only during relatively low-price periods (which tend to be low demand periods), the lower the demand, the higher is the unit cost ($/MWh) to be recovered from customers.

During periods of high demand and high price, on the other hand, Ontario tends to rely on imports and non-prescribed (or contracted) energy-limited hydro-electric generation to meet its domestic needs. This means that during these periods, an increase in price is not automatically offset by a reduction in the GA.

The relationship between HOEP, the GA and total cost of the electricity commodity is depicted in Figure 1 as a parabolic function and expressed algebraically in Equation 2.

Figure 1



Equation 2

$$Total\ Cost = \beta_0 + \beta_1 AQEW + \beta_2 AQEW^2 + u$$

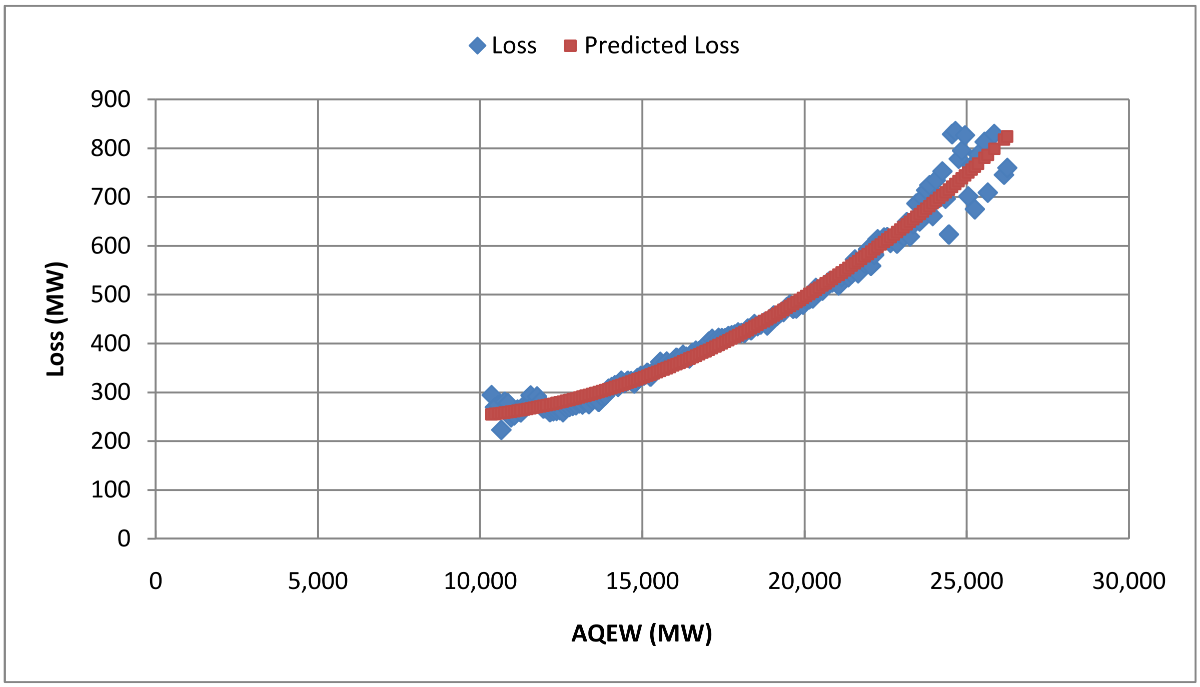
where AQEW is equal to the total Allocated Quantity of Energy Withdrawn, a measure of aggregate demand published by the Independent Electricity System Operator.

Understanding how the Global Adjustment functions in relation to the Hourly Ontario Energy Price, and how the two together function in relation to demand, is essential to understand the benefits of demand response in Ontario. First, price reductions resulting from demand reductions during critical peak periods are partially offset by increases in the GA, but the GA increase is less than the decrease in the HOEP. Second, price increases resulting from peak-shifting that causes increased demand during off-peak periods are also partially offset by reductions in the GA, but the GA reduction is more than the increase in price. Shifting demand from peaks to off-peaks not only causes prices to be lower, therefore, but also causes the total commodity cost to be lower than it otherwise would be.

6.4 Reduced losses

The laws of physics tell us that power losses in a conductor are a square function of current and the resistance of the conductor. This means, all other things being equal, that one would expect system losses in Ontario to be higher during critical peak periods.An examination of losses in relation to aggregate demand in Ontario would seem to confirm this point, as shown in Figure 2.

Figure 2



Not only are losses higher during peak periods, the cost of energy needed to compensate for these higher losses is also higher, precisely because high losses occur during high demand, high priced periods. Reducing demand during these times therefore delivers a double benefit: (1) it reduces losses, and (2) it reduces the cost of energy need to compensate for losses.

A proper cost/benefit analysis of changing the charge determinant should include the above categories and methodologies.

7 Conclusion

Our review of the costs and benefits suggests that while industrial customers who reduce demand during peak times would benefit directly from a change in the design of the network charge determinant, by paying lower transmission network charges, these customers would also bear all the costs associated with ongoing demand management activities. No demand management costs would be borne by customers who don't participate, such as would be the case with any utility or institutional programme designed to promote equivalent demand response. By placing the risk of anticipating and responding appropriately to actual and absolute critical peaks, the design would reward only those customers who participate and only to the extent that they succeed in reducing their demand during critical peaks.

Our review also suggests, however, that the benefits of the change, and the industrial demand response our analysis suggests it will induce, will be enjoyed by all customers, in the form of lower prices, reduced global adjustment amounts, lower system losses, and lower overall electricity costs. To the extent that these electricity efficiencies are realized by customers, the change will lead to higher industrial productivity, economic growth, higher investment and employment, lower inflation and increased tax revenues to governments.

Hydro One should subject AMPCO's analysis to the cost/benefit review that the Board required in its Decision with Reasons in EB-2008-0272, which we have described herein.

Attachment 1

Will greater load shifting by industrials result in lower electricity prices for all?
Evidence from Ontario, Canada
August 2010

Anindya Sen
Associate Professor
Department of Economics
University of Waterloo

Abstract

This paper offers estimates of the effects of electricity price on consumption by different industries as well as the impact of overall market demand on the Hourly Ontario Electricity Price (HOEP). Generalized Least Squares (GLS) and Instrumental Variables (IV) estimates demonstrate that some industrials do reduce demand in response to price. Perhaps more importantly, they shift consumption across peak and off peak periods in order to reap the benefits of lower prices. This is associated with a reduction in overall market demand, and therefore a lower HOEP, which benefits all consumers. The policy proposition is that schemes that encourage Real Time Pricing (RTP) and therefore efficient demand management by industrials should result in positive spillovers to all economic agents.

1. Introduction

Hydro One Networks Inc. (HONI) is a corporation owned by the Government of Ontario, and is responsible for the planning, construction, operation, and maintenance of most (97%) of the province's transmission and distribution network, which carries electricity from generating stations to local distribution companies and industrial customers.[1] HONI, and all transmission providers in Ontario, currently base network transmission charges for each customer based on their respective demand level calculated each month as the higher of: (1) The customer's demand at the time of the monthly coincident peak demand, or; (2) 85% of the customer's maximum non-coincident demand between 7:00 A.M. and 7:00 P.M. on weekdays that are not holidays.

As evident, this system offers limited consumer benefits for shifting consumption away from the month specific peak demand, and provides little incentive for efficient Time of Use (TOU) demand management for shifting consumption from peak to off-peak hours. The Association of Major Power Consumers of Ontario (AMPCO) has proposed a different methodology for calculating network transmission charges, which is currently being reviewed by the Ontario Energy Board (OEB). Specifically, that the monthly network charge determinants be constant throughout the year and be based on the customer's demand during the hour of peak demand on the five highest peak days of the previous year (referred to as the "High 5 Proposal"). The key benefits of such a system include a more efficient allocation of transmission costs according to actual use, better signals to customers regarding consumption

[1] Further details are available from its website (http://www.hydroone.com/Pages/Default.aspx).

costs, and therefore, more efficient demand shifting through reduced demand during peak hours.

Higher network transmission charges during peak hours give industrial consumers an incentive to shift their demand to off peak hours, which could theoretically benefit all consumers (residential, commercial, and industrial) through a reduction in wholesale electricity prices (the Hourly Ontario Electricity Price – or 'HOEP').[2] A significant amount of research suggests that the supply curve for electricity in Ontario and for many other jurisdictions to be 'J' shaped. In other words, the supply curve is relatively elastic with curvature determined by the marginal cost of supply generation. However, the curve becomes steeply upward sloping when system constraints are approached during peak hours. This is illustrated in figure 1. Therefore, a reduction in system demand from D_1 to D_2 – generated by lower demand by industrials responding to incentives for efficient demand management - may result in a considerable reduction in wholesale electricity prices and hence, final costs to consumers. The key consideration is whether the benefits of such a reduction will be offset by the corresponding increase in demand by industrials at some point in time. If the increase occurs during off peak hours, or the elastic portion of the supply curve (D_3 to D_4 in figure 1) then the resulting increase in price will be marginal. Consequently, the spillover benefits from lower demand or load reduction during peak hours will not be offset by equivalent increases in demand and higher prices in off-peak hours.

[2] The wholesale electricity market in Ontario is competitive, with consumers such as industrials and LDCs submitting demand requirements and suppliers offering electricity generated by different types of fuel – including nuclear, coal, natural gas, and hydro. Bids are submitted to a clearing system managed by the province's Independent Electricity Supply Operator (IESO). However, final consumers pay prices which include other charges determined by the Ontario Energy Board (OEB). Please see Melino and Peerbocus (2008) for further details.

The fundamental premise in the above analysis is that industrials respond to Real Time Pricing (RTP) and are able to shift consumption to periods of lower prices. In order to investigate the existence of such behavior, it is necessary to estimate overall demand price elasticities for the industrial sector, as well as changes in prices resulting from movements in overall demand- which itself is due to shifts in consumption by industrials during peak and off peak periods. The relevant research questions are: (1) do industrial consumers shift consumption from peak to off peak hours?; and (2) is the Hourly Ontario Electricity Price (HOEP) impacted by these changes in consumption?. Unfortunately, there exists either very limited or no contemporary empirical research – based on Canadian data - that can offer adequate answers to these specific questions.

Sen (2009) contains some analyses designed to address the above questions. However, this paper adds to Sen (2009) through the use of additional data from 2008 as well as new information on total industrial demand and demand by electricity generators, distributors, and transmitters.[3] Further, the empirical estimates have been redone using Feasible Generalized Least Squares (FGLS) which account for first order autocorrelation and unknown heteroskedaticity. We also evaluate the sensitivity of our findings through the use of Instrumental Variables (IV) intended at correcting for measurement error and pooling the data across all years of our sample. Finally, more right hand side controls are added (monthly unemployment rates, the daily exchange rate, and dummy variables for weekends and holidays) to capture the effects of other potential determinants of industrial electricity consumption.

[3] Sen, Anindya (2009), 'Do firms shift demand in response to higher prices? An empirical analysis', available at http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/99997/view/AMPCO_EVD_Attachment_20090114.PDF. This report was filed as part of AMPCO evidence for EB-2008-0272.

In summary, this paper explores these issues employing publicly available data (2005-2008) – as well as some that were obtained on special request from the Independent Electricity Supply Operator (IESO) of Ontario. These data contain aggregate demand, wholesale prices (the HOEP), and specific hourly demand by industrial sector (from 2005 to 2007) – total demand by all industrials, pulp and paper, iron and steel mills and ferro-alloy manufacturing, metallic ore mining, petroleum and coal products manufacturing, motor vehicle manufacturing, and electricity power generation, transmission, and distribution. We use the data to estimate the effects of HOEP on demand by industrial sector. We then estimate separate empirical models to evaluate the effects of load shifting on prices.

We obtain consistent findings across Feasible Generalized Least Squares (FGLS) and Instrumental Variables (IV) estimates. Some industrials reduce their demand in response to higher prices. Specifically, our results suggest that a 10% rise in the HOEP is significantly associated with a 0.3-0.7% drop in industrial demand. Perhaps more importantly, coefficient estimates of lagged electricity prices are statistically significant for most industries – implying that even in the absence of any strong regulatory incentive - firms are responsive to price signals and do shift demand between peak and off peak periods. Further, the marginal effect of electricity load on the HOEP during peak hours for summer months exceeds the impacts of corresponding effects of demand during off peak hours. These estimates are remarkably robust irrespective of which year (2005 – 2008) our estimation is based upon. In tandem, these results suggest that network charge determinants, which give industrials an incentive to shift demand from on-peak to off-peak time periods, would result in considerable benefits to all consumers.

We view our research as a contribution to the rather sparse literature on demand elasticities and electricity pricing in Ontario. While there is some research on the effects of prices on industrial and residential consumption – in most cases, the data are older and from time periods before the deregulation of electricity markets in the province (in 2002). Similarly, the literature on the determinants of the HOEP is quite thin. Our reliance on more recent data should benefit policymakers as it reflects the contemporary structure of electricity markets. Further, we employ data over a considerably long period of time, which enables us to control for the potentially confounding effects of time-invariant structural or policy shocks.

The remainder of the paper is organized as follows. The next section contains a literature review. Section III discusses the data. Section IV presents the empirical models. Empirical estimates are discussed in section V. Section VI concludes with a summary of the main findings.

II. Literature Review

A benefit of competitive markets is the implementation of Real Time Pricing (RTP) whereby consumers are directly exposed to prices that change on an hourly basis and can adjust their consumption correspondingly. Specifically, RTP schemes incent consumers to reduce their demand during peak hours with higher prices to off-peak periods with lower prices. These schemes result in efficient incentives as they reduce cross-subsidization that occurs to consumers that use a large amount of electricity during hours with high prices.

The key welfare effects of RTP programs depends on the amount of demand shifting from high price hours to time periods with lower prices. The gains to society are premised on the existence of a "J-shaped supply curve", which is initially relatively flat and based on the marginal costs of providing electricity, and then becomes vertical when capacity constraints are reached. More demand results in higher prices as power is generated from more expensive sources, with nuclear and hydroelectric being the cheapest and coal and natural gas the most expensive. However, incremental changes to prices will not be large until capacity constraints are approached and the supply curve becomes roughly vertical. If this describes the situation during peak hours in summer, it is possible that society would gain from a reduction in demand as the downward shift in the demand curve occurs on the vertical part of the supply curve. The concern is that the reduction in demand must correspond to some increase in demand during off peak hours, resulting in an increase in prices. However, any increase in prices will be minimal if it occurs on the flat horizontal part of the supply curve. Such an increase in price will, therefore, not offset the gains from lower prices defined off the vertical part of the supply curve during peak hours.

In terms of recent U.S. research, Borenstein (2005), Borenstein and Holland (2005), and Holland and Mansur (2005) rely on simulations to estimate the gains to RTP schemes. However, Braithwait (2000) and Boisvert et al. (2007) estimate the differential effects of peak and off prices on consumption. Braithwait (2000) employ daily consumer level data from June-September of 1997. Boisvert et al. (2007) employ data on 119 large customers from 2000-2004. Both these studies estimate price responsiveness of electricity demand between peak and off-peak hours.[4]

With respect to Ontario data, Mountain and Lawson (1992, 1995) use data from an experiment conducted with respect to 500 households in 1982-83. A vast majority of these households chose to go on time of use rates till 1988. They compute peak and off-peak elasticities by month and find a 'high' compensated peak hour elasticity of -0.064 (Mountain and Lawson, 1995). Mountain uses monthly data for 39 firms from 1970-1984 in order to

[4] As noted by Boisvert et al. (2007), this approach is motivated by other studies (Taylor et al. (2005), and Patrick et al. (2001)) who either suggest or find substitutability in electricity consumption between afternoon (peak) and off-peak hours.

estimate industrial load factors (1990). Hsiao, Mountain and Illman (1995) employ data on 49 Ontario households in 1986 and 347 households in 1983, but focus on the relationship of appliance ownership with respect to load. Ham, Mountain, and Chan (1997) analyze the 1985 Ontario Hydro experiment which studied the effects of time of use (TOU) on small commercial customers. They find peak elasticities ranging from -0.091 to -0.067 for various appliances. They also obtain aggregate statistically significant own-price elasticities for total electricity usage (-.134 in the winter and -.114 in the summer). These elasticities are slightly higher than those suggested by Mountain (1993), with respect to the residential sector (-.12 in the winter and -.09 in the summer).

The above discussion suggests a considerable amount of Ontario specific research on demand elasticities with respect to the residential, commercial, and industrial sectors. However, all of these studies are based on pre-reform (2002) data. In terms of more recent research, Angevine and Hrytzak-Lieffers (2007) investigate the effects of price on consumption by industrials during the 2002-2003 and 2006-2007 and estimate separate price elasticities for peak and off peak periods. However, they do not estimate the effects of lagged prices. Peerbocus and Melino (2008) investigate the effects of Ontario price shocks on export and import volumes. It is, therefore, fair to say that policy relevant questions on how aggregate industrial demand responds to price over a long time period, as well as what the statistically important determinants of the HOEP are – remain relatively unexplored. This is the gap that we address in this study.

III. Data

Data on the HOEP and corresponding market demand, hourly exports and imports of electricity are all publicly available data, and can be downloaded from the website of the

Independent Electricity Supply Operator (IESO) of Ontario.[5] Hourly demand by industry sector – total industry demand, iron and steel mills and ferro-alloy manufacturing , metal ore mining, motor vehicle manufacturing, petroleum and coal products manufacturing, pulp, paper and paperboard mills, electric power generation, transmission and distribution (excluding local distribution companies (LDCs)) – were obtained on special request from the IESO. These data consist of electricity consumption of industrials that are directly connected to the transmission grid and can thus react directly to the HOEP. The IESO also provided us with data on hourly supply by each generator in the province. These data not only contain details on firm affiliation, but the type of power, allowing us to construct a Herfindahl Hirschman Index in order to capture the effects of market power among suppliers, as well as control for the effects of different sources of electricity generation on an hourly basis.[6] We also employ data on monthly provincial unemployment rates and the daily exchange rate, in order to account for the effects of economic factors that could plausibly affect industry specific demand for electricity. As discussed below, conditional on data constraints, we either employ data from 2005-2007 or 2005-2008 in our empirical analyses.

Table 1 contains some descriptive statistics for electricity consumption by industrials during summer months (May, June, July, and August). Consumption by industrials that are directly connected to the transmission grid constitutes roughly 15-16% of total Ontario demand – a statistic that is consistent over time. Iron and steel mills, metal ore mining, and pulp and

[5] As noted on its website (http://www.ieso.ca/imoweb/siteShared/whoweare.asp), the Independent Electricity System Operator (IESO) is a not-for-profit organization established in 1998 by the Electricity Act of Ontario. The IESO is basically responsible for monitoring and ensuring the efficient working of the Ontario electricity market. It connects all participants – generators, transmitters, retailers, industries and businesses that purchase electricity directly from the system, and local distribution companies (LDCs). All market participants must meet the standards enacted and enforced by the IESO.

[6] The Herfindahl Hirschman Index is simply the sum squared of firm specific market shares.

paper are the largest consumers, accounting for roughly 17% to a bit over 20% of total industrial demand.

Figure 2 graphs total demand by industrials against the HOEP. All the data are averaged across summer months between 2005 and 2008. The trends conform to intuition as industrials consume a significant amount of electricity during off peak hours when prices are low, and reduce demand during high price period peak hours. However, there is significant variation across industries. Figure 3 demonstrates that consumption by iron and steel mills drops during early peak hours, but then climbs thereafter. On the other hand, demand by metal ore mining (figure 4) is considerably lower during peak hours. Figure 5 demonstrates that consumption by motor vehicle manufacturing correlates positively with the HOEP – probably due to the fact most production usually occurs during regular workday hours. In contrast, demand by petroleum and coal products manufacturing is relatively constant across time (figure 6). On the other hand, average demand by pulp and paper mills (figure 7) and electricity power generators, transmitters, and distributors (figure 8) quite clearly demonstrate an inverse relationship with the HOEP.

IV. Estimation Methodology

Estimating Peak and Off Peak Demand Elasticities

Consistent with previous studies we focus on estimating price elasticities by peak and off-peak periods. Braithwait (2000) and Boisvert et al. (2007) offer a methodology to estimate substitution elasticties between on and off peak periods. The critical assumption driving their models is the availability of customer specific data – for residential or industrial consumers - on actual electricity expenditure and other demographic characteristics. These studies employ a three level model in order to capture how consumers rationally allocate their expenditures on electricity. First, consumers choose consumption within the week, conditional on expected electricity prices. Second, decisions are made regarding weekday and weekend consumption. Finally, consumers must decide how much of their budget constraint to spend on electricity consumption. This three-stage demand model can be captured by the following indirect utility function:

V = V (Pt [Pw (Pp, Po), Pe], Pg, Y) (1)[7]

Pt represents overall electricity prices, which can be decomposed to: weekday price (Pw), which are further a function of peak (Pp) and off-peak (Po) prices in the peak, shoulder and off-peak periods (critical prices are averaged with the peak prices where appropriate); Pe is the weekend price; and Pg captures prices of other goods. To implement the model, we must specify a particular functional form for the price indexes in (1). Using a Constant Elasticity of Substitution (CES) functional form yields the following equation[8];

$$\ln(E_t / E_g) = a_3 + (1-\sigma_3)\ln(P_t / P_g) + \theta \ln(Y / P_g) + \omega D_{TOU} \qquad (2)$$

where

Y	denotes customer income,
E_t	denotes total electricity expenditures by customer,
E_g	denotes customer expenditures on non-electricity goods (set equal to Y - E_t),

[7] Braithwait further decomposes consumption according to peak, off peak and shoulder prices. Specifically, 1 am - 8 am is off peak, 9 am - 2 pm is shoulder, 3 pm – 6 pm is peak, 7 pm – 8 pm is shoulder, 9 pm – 12 am is shoulder.

[8] Exact derivations are available from Braithwait (2000).

The advantage of the CES functional form is its simplicity and parsimony. However, the drawback is that it imposes a constant elasticity of substitution across different time periods. On the other hand, a more generalized Leontief functional form allows one to estimate different elasticities of substitution that vary across time periods. This functional form yields the following system of equations:

$$\ln(K_i / K_k) = \ln\left[\sum_{j=1}^{n} \delta_{ij}\left(P_j / P_i\right)^{1/2}\right] - \ln\left[\sum_{j=1}^{n} \delta_{kj}\left(P_j / P_k\right)^{1/2}\right], i = 1,\ldots(k-1) \qquad (3)$$

where K_i = usage in period i, and the periods are defined by price levels and time periods.

As noted above, these methodologies are appropriate when it is possible to access individual level customer data. They are intended at estimating how consumers substitute electricity consumption over time – in response to prices, while holding expenditure on other goods and income constant, thus yielding compensated demand elasticities. This study employs aggregate level data on electricity consumption by industrial sectors, which face the same price (HOEP) at a point in time. Therefore, we cannot use the above methods. Instead, we employ the following empirical specification (Stone's expenditure system) based on standard consumer theory[9];

$$ln(K_i) = \beta_0 + \beta_1 ln P_i + \beta_2 ln P_j + Z + \varepsilon_i \qquad (4)$$

Average electricity usage or consumption during a specific time period or consumption (K_i) is a function of average prices in that period (P_i) as well as other time periods (P_i). ε_i is the error term, which is assumed to be independently and identically distributed. If Z succeeds in controlling for income shocks, then β_1 and β_2 are compensated price elasticities.

[9] This is consistent with the approach employed by Melino and Peerbocus (2008).

We estimate equation (4) employing variation across peak and off peak prices and aggregate Ontario demand from 2005-2008. The hours are broadly divided into peak (7 am to 6:59 pm) and off peak (7 pm to 6:59 am the next day). Consumption is assumed to be a function of average prices during the specific time period (P_i) as well lagged prices (P_j). Hence, when the data refers to electricity consumption during *peak* hours (7 am to 6:59 pm), the lagged price is average *off peak* prices from 12 am to 6:59 am of the same day, but earlier in the morning. On the other hand, when K_i is electricity consumption during *off peak* hours (7 pm to 6:59 am the next day), the lagged price is average *peak* price between 7 am to 6:59 pm of the same day, reflecting the effects of electricity substitution *across* days. In both cases, if there is substitutability, then β_2 will still be positive. Further, we are effectively constraining the demand elasticity of peak demand with respect to off peak price and the demand elasticity of off peak demand with respect to peak price, to be the same.

Finally, there is an important caveat to the interpretation of β_2. A statistically significant relationship between lagged prices and current demand might reflect some degree of market inertia, with price shocks in some hours having some residual effects over a longer time period. However, the implication also is that industrials have some ability to forecast changes over a relatively short time period, and accordingly adjust demand in order to exploit benefits from lower prices that would occur later in the day. This is certainly a reasonable assumption given the availability of day ahead price forecasts from the IESO and general weather forecasts.

Z captures the potentially confounding effects of other unobserved factors that impact industry profitability and therefore affect electricity consumption. Dummies are used to distinguish variation in electricity consumption during weekends and non-weekend holidays.

We will also alternatively employ month specific dummies and month specific unemployment rates, the daily Canada/U.S. exchange rate, and hourly temperature variables.

The above discussion motivates our reliance on a simple empirical specification, which in part is due to our access to aggregate rather than micro-level data. As a result, there is possibility that empirical estimates may suffer from aggregation error. However, as pointed out by Denton and Mountain (2006) micro-level models that are a misspecification of the underlying micro utility-maximizing model, may produce errors of similar order. In this respect, relying on aggregated data could reduce errors from an incorrect micro-level model, resulting in gains from the perspective of empirical estimation (Grunfeld and Griliches (1960), Hartley 1997)).

Given the obvious potential for correlation in electricity prices within the day, we ran a Breusch-Godfrey Lagrange Multiplier test for first order autocorrelation. The null hypothesis of no first order autocorrelation was rejected in all specifications. Therefore, the estimation methodology is Generalized Least Squares (GLS), which corrects for unknown heteroskedasticity and first order autocorrelation. Comparable results were obtained by clustering standard errors by day of month in order to account for unobserved correlations that are day specific or across days. Table 2 contains summary statistics.

Estimating the effects of Hourly Load on the HOEP

The above discussion outlines our approach to estimating industry specific elasticities. The other contribution of this research is through our analysis of the effects of province specific demand on the Hourly Ontario Electricity Price (HOEP). The empirical specification that we employ is a standard reduced form expression;

$$P_i = \beta_0 + \beta_1 OnDem_i + \beta_2 EXP_i + \beta_3 IMP_i + \beta_4 HHI_i + \beta_5 NUCP_i + \beta_6 COAL_i + \beta_7 HYDRO_i + \beta_8 GAS_i + \beta_9 EXCHR_i + \beta_{10} UNEMP_i + \beta_{11} day_t + \sum_i h + \sum_t m + \varepsilon_i \qquad (5)$$

The above model is a common methodology to evaluate the impacts of demand, costs, and market structure on observable energy prices in a given market. P_i is the Hourly Ontario Energy Price expressed in \$/MWh and is a function of total ontario demand (*$OnDem_i$*), imports (*IMP_i*), exports (*EXP_i*) and the mix of power supply between coal (*$COAL_i$*), nuclear (*$NUCP_i$*), gas (*GAS_i*), and hydro (*$HYDRO_i$*) all in MW - in each hour. By employing constructs for the source of electricity supply (coal, nuclear, gas, or hydro generated) we are not only controlling for the impacts of supply, but also conditioning empirical estimates of load demand to whether the source of supply has differential impacts on electricity prices.

We also construct a Herfindahl-Hirschman Index (*HHI_i*) which is a measure of market power within an industry.[10] Finally, we employ the average daily U.S.-Canada Exchange Rate (*$EXCHR_i$*) and the average monthly Ontario Unemployment Rate (*$UNEMP_i$*) in order to capture the effects of macro-economic variables. *Day_t* is simply the day of the month and is intended to reflect the effects of trends within the month. Dummy variables are constructed for each hour ($\sum_i h$) and month ($\sum_t m$) in order to control for the potentially confounding effects of other time specific unobserved determinants of wholesale electricity prices. As in the case with estimating the relationship between industrial demand and price, the estimation methodology is Generalized Least Squares (GLS) with standard errors corrected for unknown

[10] The Herfindahl-Hirschman Index (HHI) is the metric typically employed by antitrust agencies in different countries to measure industry-specific competitive effects or market structure and to identify and establish enforcement and investigative thresholds in the analysis of horizontal mergers. The HHI is quite easy to construct, being simply the sum of the squared market shares of firms, with market shares typically being constructed from firms' sales.

heteroskedasticity and first order serial correlation. We did not obtain any difference in our results by clustering the standard errors by hour or day, and these results are omitted for the sake of brevity. Summary statistics are in table 2. Finally, we note that unlike the case with demand elasticities, our estimates of the effects of demand on price are derived from 2005, 2006, and 2007 data, as this is the time span of generator specific supply that we obtained from the Independent Electricity Supply Operator (IESO).

V. Empirical Results

Demand elasticities by industry

Table 3 contains benchmark GLS estimates of lagged and contemporaneous prices on demand by industry that are conditioned on month specific dummies. We econometrically estimate the relationship between demand and price for each year (2005-2008) in order to assess possible changes over time. As discussed above, econometric estimates are based on year specific samples over summer months (May, June, July, and August) with hourly prices and demand averaged across peak (7 am – 6:59 am) and off peak (7 pm – 6:59 am) hours. Therefore, each day has two observations, enabling us to exploit within as well as across day variation over a period of four months.

The first key finding is that, on average, total demand by all industrials (panel A) are impacted by contemporaneous prices. Specifically a 10% increase in hourly prices is significantly correlated with a roughly a 0.5 –0.8% fall in demand (in most columns) – a result that is statistically significant at the 1% level. We obtain estimates from -0.02 to -0.06 with respect to the metal (panel A) and iron and steel industries (panel B). The coefficient estimate of current prices is even larger with respect to the pulp and paper industry (panel F). Our estimates suggest that a 10% increase in electricity prices is significantly associated (at the 1%

level of significance) with a 1.3-2.5% decline in electricity demand by the pulp industry. However, coefficient estimates of current prices with respect to demand by petroleum and coal products are statistically insignificant across most columns. While coefficient estimates of price for demand by motor vehicle manufacturing are statistically significant – they possess a positive sign. However, these results correspond with the intuition suggested by the figures. Electricity demand by petroleum and coal products seems to be time invariant, while the positive correlation between the HOEP and consumption by motor vehicle manufacturing reflects production that follows a typical work day schedule.

What is perhaps even more intriguing is that coefficient estimates of average prices in the previous 12 hours is significantly correlated with an increase in *contemporaneous* hourly demand across all industries for most years – suggesting that industries do shift demand across peak and off peak periods. Further, the magnitudes of coefficient estimates are remarkably consistent across industrial sector. Empirical estimates imply that a 10% increase in average prices 12 hours ago is significantly associated with a roughly 0.1-1.5% increase in current consumption by all industrials, iron and steel mills, metal ore mining, motor vehicle manufacturing, and petroleum and coal products manufacturing, controlling for the effects of other factors. On the other hand, demand elasticities for pulp and paper and electric power generation are even larger in magnitude relative to other industries– ranging from -0.09 to -0.3. These findings are statistically significant at either the 5% or 1% levels of significance.

Table 4 offers some sensitivity analyses by replicating the results in table 3. The only difference is that we use the month specific unemployment rate, daily Canada-U.S. exchange rate, and holiday and weekend dummies, instead of month dummies. The use of these covariates allow us to specifically capture variation in economic and other unobserved shocks experienced by industries.

Remarkably, our results remain unaltered. In the first four columns, a 10 % increase in current prices is significantly correlated with approximately a 0.2-0.5% drop in demand by all industrials, iron and steel mills, and metal ore manufacturing. While coefficient estimates of prices for motor vehicle manufacturing and petroleum and coal products manufacturing are either statistically insignificant or possess the wrong sign, demand elasticities with respect to pulp and paper and electricity are larger (-0.10 to -0.4). These findings are consistent with Angevine and Hrytzak-Lieffers (2007). As before, coefficient estimates of lagged prices are in many cases statistically significant (at the 1% or 5% levels), with larger effects for pulp and paper and electricity transmission, generation, and distribution.

We also evaluated the sensitivity of our findings with the inclusion of average temperature based covariates. Specifically, we were able to download hourly temperature data for Thunder Bay and Toronto from the National Climate Data and Information Archive.[11] Toronto was chosen because of its relative central location in the province, while Thunder Bay is employed in order to capture the effects of weather trends in areas that are located further west. Our results remained quite comparable. Lagged electricity prices were still positive and statistically significant with respect to most industries. On the other hand, temperature covariates for Toronto and Thunder Bay were sporadically significant and are thus, not used for further analyses.

Instrumental Variables

Our empirical specification assumes that changes in prices exogenously affect demand. However, shifts in demand due to factors other than price - will impact equilibrium prices. An

[11] These data are available at http://www.climate.weatheroffice.gc.ca/climateData/canada_e.html.

inability to account for these factors will result in a correlation between the coefficient estimate of price and the right hand side error term, leading to confounded results and flawed inference. The challenge is to locate an instrument that might plausibly affect variation in Ontario prices and yet remain uncorrelated with the right hand side error term.

We propose to evaluate the sensitivity of our findings by employing electricity prices from other jurisdictions as instruments for the Hourly Ontario Electricity Price (HOEP). Specifically, we employ electricity prices from New York and the Pennsylvania-New Jersey-Maryland (PJM) markets as instruments. The rationale is that these prices are correlated with each other as they belong to the North American market and all of these jurisdictions export and import electricity to each other.[12] However, demand in either of these markets should not be directly affected by each other's prices. Therefore, consistent with the intuition offered by Peerbocus and Melino (2008), the use of these instruments will enable us to use observed price and quantity data, which reflect equilibrium demand equal to supply, and identify the demand curve, or the effects of price on demand.

The use of instrumental variables may also be useful in correcting measurement error from an incorrect empirical specification. Specifically, suppose that the 'correct' model is

$$ln\ (K_{peak}/K_{off}) = \beta_0 + \beta_1 ln(P_{peak}/P_{off}) + Z_t + \varepsilon_t \qquad (6)$$

In other words, as implied by (3), the natural logarithm of the ratio of peak and off-peak demand is a function of the natural logarithm of corresponding prices.[13] (6) can then be rewritten as

$$ln\ K_{peak} = \beta_0 + \beta_1 lnP_{peak} - \beta_1 lnP_{off} - lnK_{off} + Z_t + \varepsilon_t \qquad (7)$$

---

[12] As noted by Peerbocus and Melino (2008) – between 80-85% of Ontario exports go to the New York market.

[13] We are assuming a linear approximation to (3) that is compatible with aggregate rather than individual level data.

or

$$ln\ K_{peak} = \beta_0 + \beta_1 lnP_{peak} + \beta_2 lnP_{off} + Z_t + v_t \qquad (8)$$

where $\beta_2 = -\beta_1,\ v_t = -\ lnK_{off} + \varepsilon_t$

While (8) is similar to (4), it is clear that coefficient estimates of prices will be inconsistent and biased if demand during off peak hours is correlated with either peak or off-peak prices. Instrumental variables have the potential to reduce some of this measurement error.

Table 5 presents first stage regressions for each year. The results correspond to intuition as a \$1 increase in the New York and the PJM price is significantly correlated (at the 1% level) with 0.7-0.9 cents rise in the HOEP. Further, the *F* statistics from the joint test of significance (of the null hypothesis that the coefficient estimates of the instruments are equal to zero) comfortably exceed the value of 10, suggested by Staiger and Stock (1997).

Table 5 also contains corresponding second stage estimates. Empirical estimates are comparable to GLS results. Coefficient estimates of current prices with respect to motor vehicle manufacturing and petroleum and coal products manufacturing are either insignificant or possess a positive sign. On the other hand, an increase in the HOEP is in most cases, significantly correlated (at the 1% or 5% levels) with a reduction in demand by all industrials, the iron and steel mills, metal ore mining, and the pulp and paper industry. The coefficient estimates of current prices are comparable in magnitude to prior estimates and relatively consistent over time. With the exception of the petroleum and coal products manufacturing industry, coefficient estimates of lagged electricity prices are positive and statistically significant (at the 1% level) ranging between 0.02 to 0.11 in value for all industrials, iron and steel mills, metal ore mining, and from 0.11 to 0.37 for pulp and paper and electricity power generation, transmission, and distribution.

Table 6 offers some further sensitivity analyses. So far we have not exploited the panel features of our data as we have run separate regressions for each year. The table contains estimates obtained from pooling together data across all years and employing year dummies in order to control for the potentially confounding effects of time specific shocks. As can be seen, we do not obtain very different results.

Estimating the effect of load on the HOEP

The above results offer some evidence that some industries do shift consumption over hours in order to reap the benefits of lower electricity prices. The next question is whether there are differences in the effects of overall demand on the hourly electricity price. A larger marginal effect during peak hours would suggest that the benefits of reduced consumption during peak periods will not be offset by a corresponding increase over off-peak hours. Tables 7 and 8 contain GLS estimates of equation (5) with respect to peak and off peak hours, respectively. We use a levels specification, based on results from Likelihood Ratio tests based on Box-Cox regressions that do not reject the use of a levels specification.

Estimates from table 7 demonstrate that a 1000 MW increase in Ontario demand is significantly associated (at the 1% level) with a \$16 to \$20 increase in the HOEP. In terms of other estimates, exports (imports) is positively (negatively) and significantly correlated (at the 1% level) with higher price. The one source of power generation that is significant (at the 1% level) across all columns is nuclear electricity, which possesses negative signs across all columns.

Results contained in table 8 offer some further evidence on the curvature of the elastic supply curve (inelastic – peak, elastic – peak). Specifically, coefficient estimates of Ontario demand are smaller in magnitude relative to estimates in table 7. The gap in 2005 and 2007 are especially large. The coefficient estimates of demand during peak hours in 2005 and 2007 imply that a 1,000 MW increase in demand is correlated with a $19.8 and $16.3 rise in prices, respectively. On the other hand, the comparable estimates for off peak hours are $12.69 and $7.82. The estimates of other covariates are otherwise comparable to table 7.

VI. Conclusion

There is very little research on the effects of prices on electricity consumption by the industrial sector in Ontario. Similarly, there is an absence of econometric studies on the effects of different factors on the HOEP. This paper attempts to fill this gap by employing data for summer months from 2005-2008. In this respect, the use of data over multiple years enables us to assess the sensitivity of our findings to year specific shocks.

We obtain remarkably consistent findings across different estimation methodologies. Most industries – with the exception of motor vehicle manufacturing and petroleum and coal products manufacturing – respond in varying degrees to contemporaneous changes in price. What is even more robust are the effects of lagged prices. Specifically, an increase in lagged prices is significantly associated with higher current consumption – offering evidence that industrials do shift consumption across time in order to exploit the benefits of lower prices during off peak hours. We also find that lower market demand is associated with a decline in the HOEP. In tandem, these findings offer support to the notion that policies which encourage efficient demand management by industrials will result in positive spillovers to all consumers.

References

Angevine, Gerry and Dara Hrytzak-Lieffers (September, 2007). 'Ontario Industrial Electricity Demand Responsiveness to Price.' The Fraser Institute, Energy Series, Technical Paper

Boisvert, Richard, Peter Cappers, Charles Goldman, Bernie Neenan and Nicole Hopper. (2007). 'Customer Response to RTP in Competitive Markets: A Study of Niagara Mohawk's Standard Offer Tariff,' *The Energy Journal*, 28(1), 53-74.

Boisvert, Richard, Peter Cappers, Bernie Neenan and Bryan Scott. (2004). 'Industrial and Commercial Customer Response to Real Time Electricity Price.' Unpublished document, Neenan Associates (December 10).

Borenstein, Severin. (2005). 'The Long-Run Efficiency of Real-Time Electricity Pricing', *The Energy Journal*, 26(3), 93-116.

Borenstein, Severin and Stephen Holland. (2005). 'On the Efficiency of Competitive Electricity Markets with Time-invariant Retail Prices,' *RAND Journal of Economics*, 36(3), 469-93.

Borenstein, Severin, James B. Bushnell and Frank A. Wolak (2002). 'Measuring Market Inefficiencies in California's Deregulated Wholesale Electricity Market.' *American Economic Review*, 92(5), 1376–1405.

Braithwait. S. (2000). 'Residential TOU Price Response in the Presence of Interactive Communication Equipment,' in A. Faruqi and K. Eakin (eds.) *Pricing in Competitive Electricity Markets.* Boston MA: Kluwer Academic Publishers

Cheng, William and Dean C. Mountain (1993). 'Econometric Study of the 1992 Time−of−Use Impact of Direct Industrial Customers.' Product Testing and Analysis Department and Economics and Forecasts Division, Ontario Hydro.

Denton, Frank T., Dean C. Mountain, Byron G. Spencer (2006). 'Errors of Aggregation and Errors of Specification in a Consumer Demand Model: ATheoretical Note.' *The Canadian Journal of Economics*, 39(4), 1398-1407.

Grunfeld, Y., and Z. Griliches (1960). 'Is Aggregation Necessarily Bad?'. *Review of Economics and Statistics*, 42, 1-13.

Hartley, J.E. (1997). *The Representative Agent in Macroeconomics* (London: Routledge)

Ham, John, Dean.C. Mountain and M. W. Luke Chan (1997). 'Time−of−Use Prices and Electicity Demand Allowing for Selection Bias in Experimental Data.' *RAND Journal of Economics*, 28(0), s113-s141.

Herriges, A., S. M. Baladi, D.W. Caves and B. F. Neenan (1993). 'The Response of Industrial Customers to Electric Rates Based Upon Dynamic Marginal Costs.' *Review of Economics and Statistics*, 75(20), 446-454.

Hopper, Nicole, Charles Goldman and Bernie Neenan (2006). 'Demand Response from Day – Ahead Hourly Pricing for Large Customers.' *The Electricity Journal*, 19(3), 52-63.

Hsiao, Cheng, Den, Mountain, and Kathleen Illman (1995). 'A Bayesian Integration of End-Use Metering & Conditional Demand Analysis.' *Journal of Business and Economics Statistics*, 13(3), 315 – 326.

Mansur, Erin and Stephen Holland (2006). 'The Short-Run Effects of Time−Varying Prices in Competitive Electricity Markets.' *The Energy Journal*, 27(4), 127-155.

Melino, Angelo and Nash Peerbocus (2008). 'High Frequency Export and Price Responses in the Ontario Electricity Market.' *The Energy Journal*, 29(4), 35-51.

Mountain, Dean C. (1989). 'A Quadratic Quasi Cobb−Douglas Extension of the Multi−Input CES Formulation.' *European Economic Review*, 33, l43-l58.

Mountain, Dean C. and Evelyn L. Lawson (1992). 'A Disaggregated Non−Homothetic Modeling of Responsiveness to Residential Time-of-Use Electricity Rates,' *International Economic Review*, 33(1), 181-207.

Mountain, Dean C. (1993). 'An Overall Assessment of the Responsiveness of Households to Time-of-Use Electricity Rates: The Ontario Experiment.' *Energy Studies Review*, 5, l90−203.

Mountain, Dean C. (1995). 'A Preliminary Econometric Examination of Real Time Pricing, Ontario Hydro.'

Mountain, Dean C. and Evelyn L. Lawson (1995). 'Some Initial Evidence of Canadian Responsiveness to Time-of-Use Electricity Rates: Detailed Daily and Monthly Analysis.' *Resource and Energy Economics*, l7, 189-212.

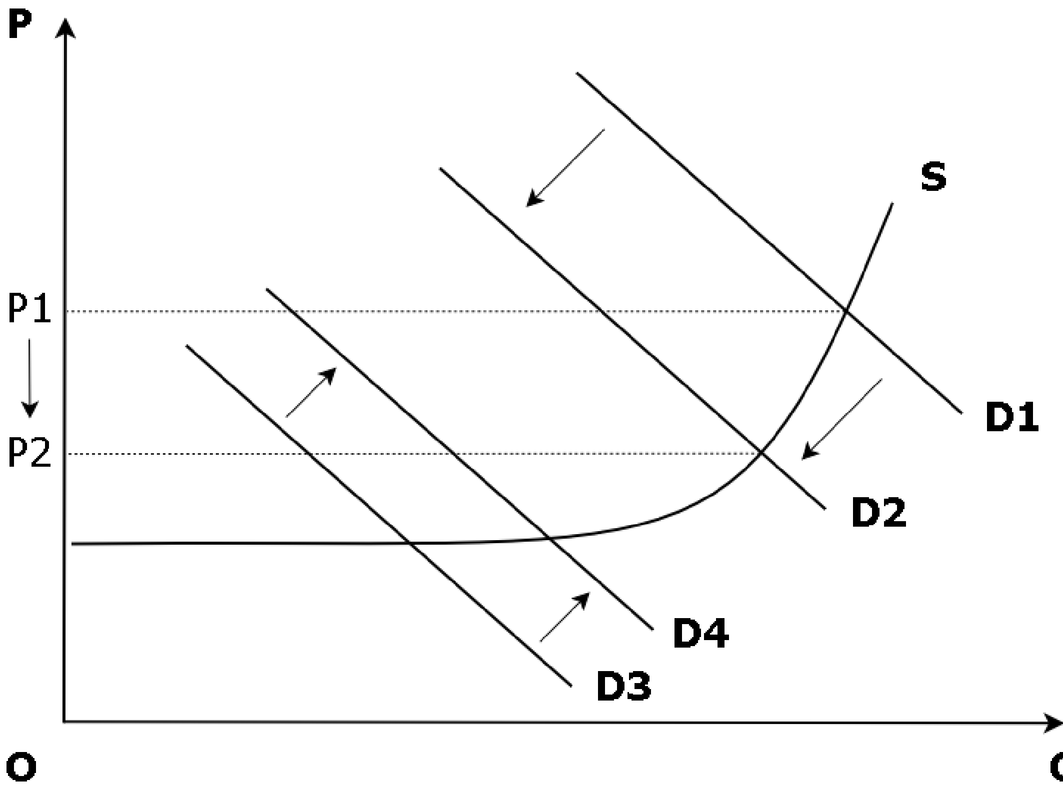
Patrick, R., and F. Wolak. (2001). 'Estimating Customer Level Demand for Electricity under Real Time Market Conditions.' NBER Working Paper 8213.

Schwarz, P.M., T.N. Taylor, M. Birmingham and S.L. Dardan. (2002). 'Industrial Response to Electricity Real−Time Prices: Short Run and Long Run.' *Economic Inquiry*, 40(4), 597−610.

Staiger, D., Stock, J.H. (1997). 'Instrumental Variables Regression with Weak Instruments. '*Econometrica*, 65, 557-586.

Taylor, T., Schwarz, P.M., and J. Cochell (2005). '24/7 Hourly Responses to Electricity Prices: Pricing with up to Eight Summers' Experience.' *Journal of Regulatory Economics*, 27(3), 2235-2262.

Figure 1


P
P1
P2
O
Q
S
D1
D2
D4
D3

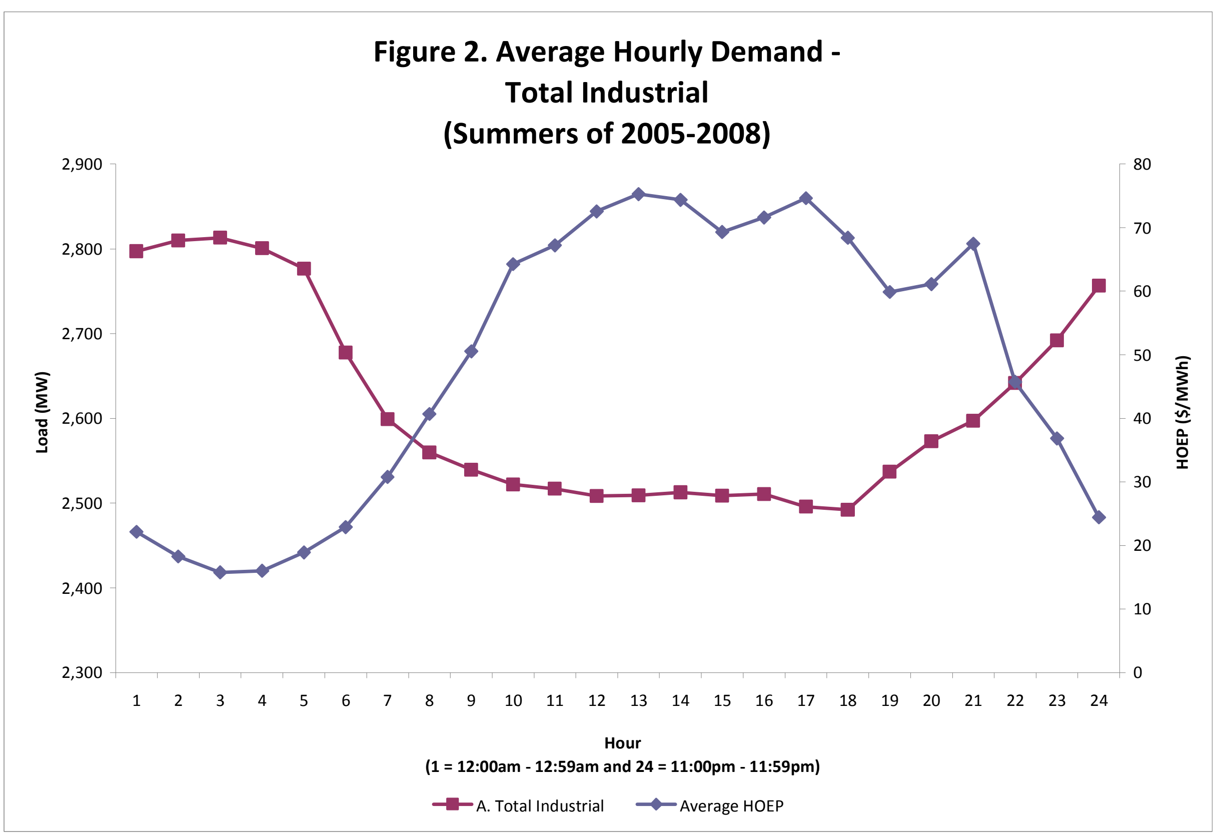


Figure 2. Average Hourly Demand -
Total Industrial
(Summers of 2005-2008)
Load (MW)
HOEP ($/MWh)
2,900
2,800
2,700
2,600
2,500
2,400
2,300
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
(1 = 12:00am - 12:59am and 24 = 11:00pm - 11:59pm)
A. Total Industrial
Average HOEP

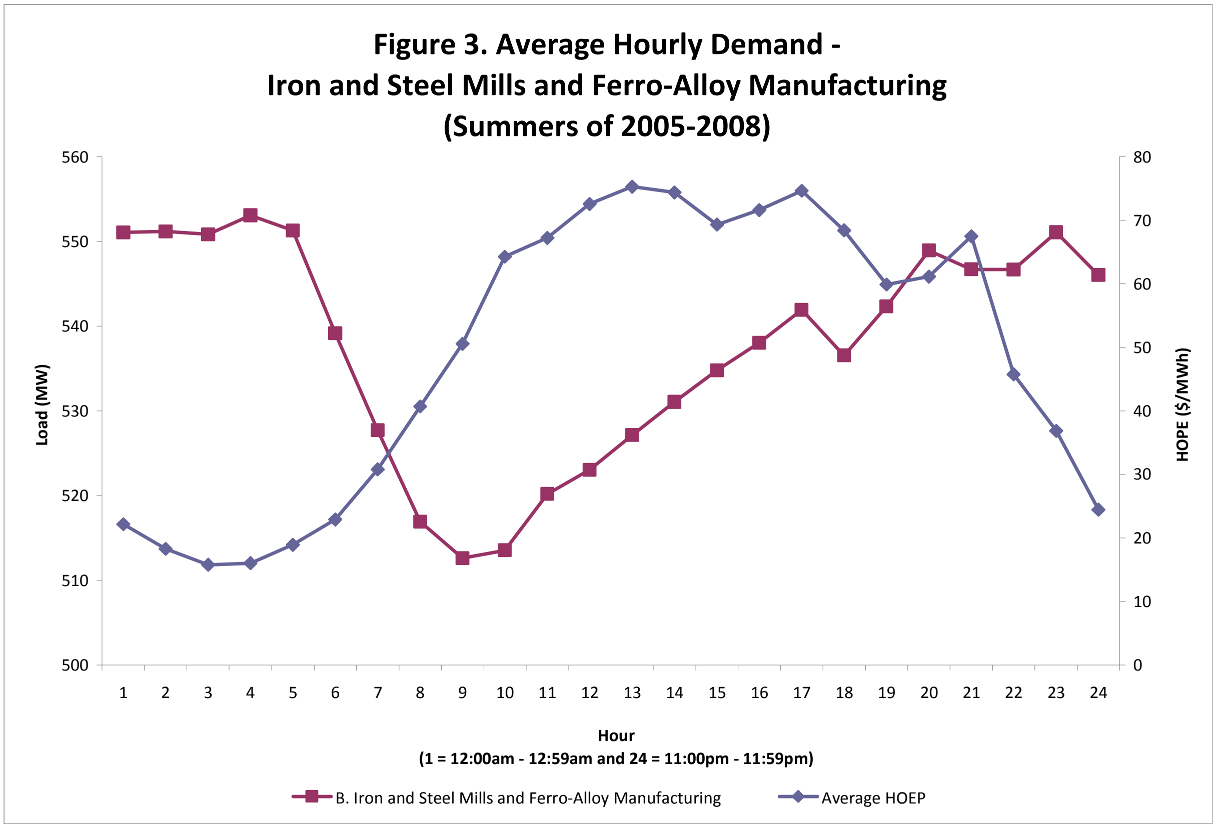


Figure 3. Average Hourly Demand -
Iron and Steel Mills and Ferro-Alloy Manufacturing
(Summers of 2005-2008)
Load (MW)
HOPE ($/MWh)
Hour
(1 = 12:00am - 12:59am and 24 = 11:00pm - 11:59pm)
B. Iron and Steel Mills and Ferro-Alloy Manufacturing
Average HOEP

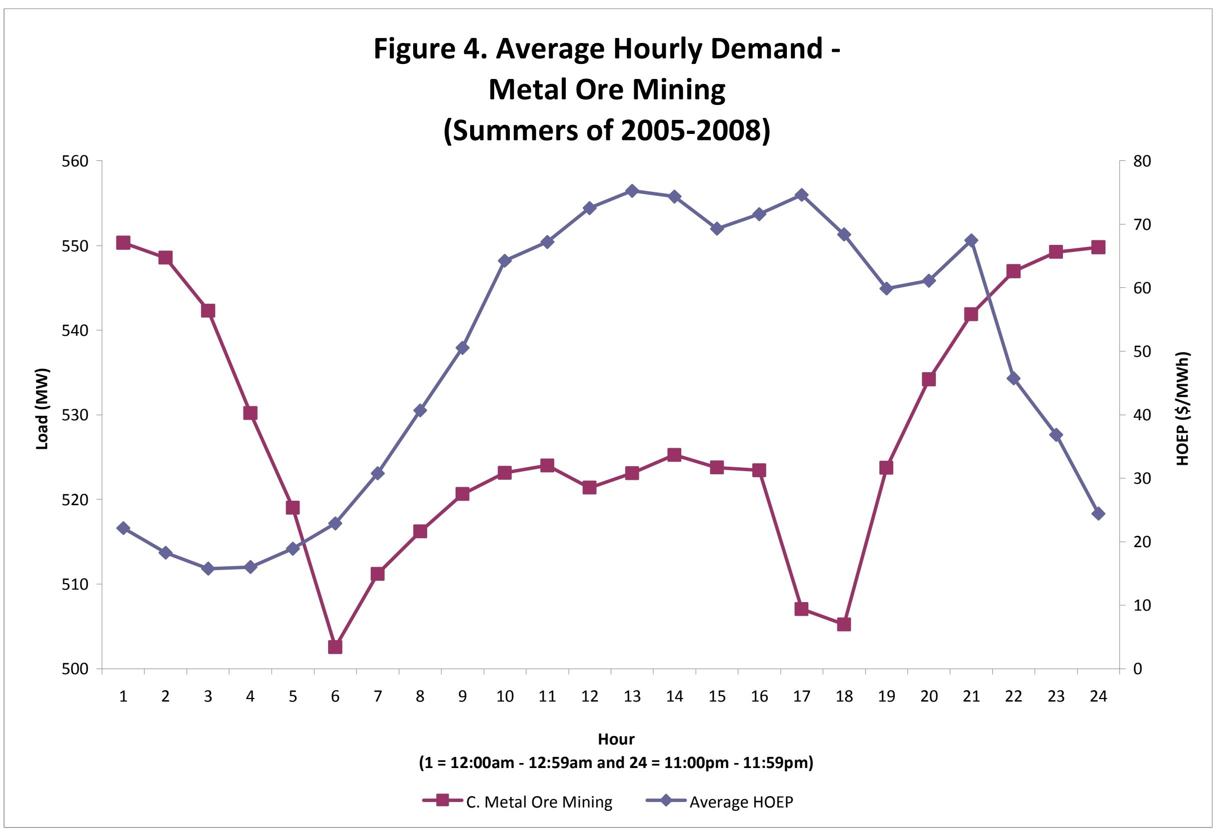


Figure 4. Average Hourly Demand -
Metal Ore Mining
(Summers of 2005-2008)
Load (MW)
HOEP ($/MWh)
Hour
(1 = 12:00am - 12:59am and 24 = 11:00pm - 11:59pm)
C. Metal Ore Mining
Average HOEP

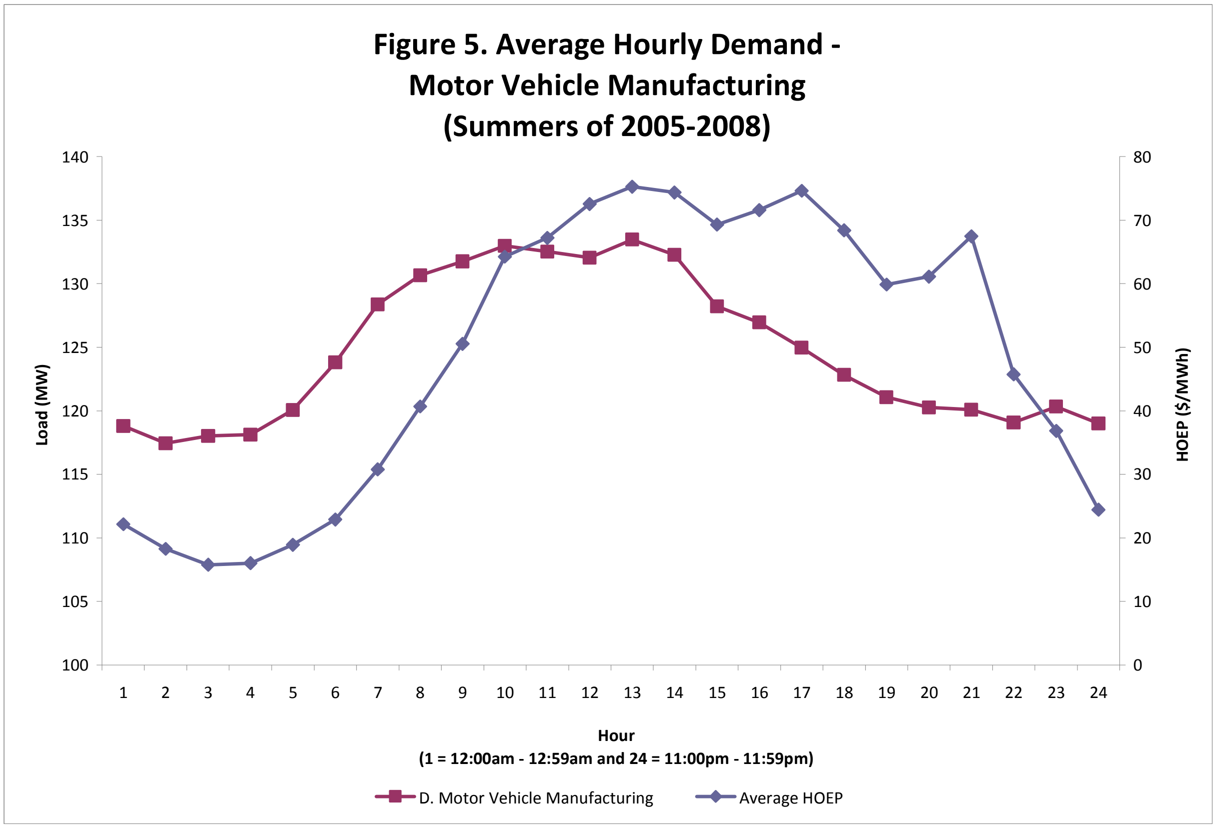


Figure 5. Average Hourly Demand -
Motor Vehicle Manufacturing
(Summers of 2005-2008)
Load (MW)
HOEP ($/MWh)
140
135
130
125
120
115
110
105
100
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
(1 = 12:00am - 12:59am and 24 = 11:00pm - 11:59pm)
D. Motor Vehicle Manufacturing
Average HOEP

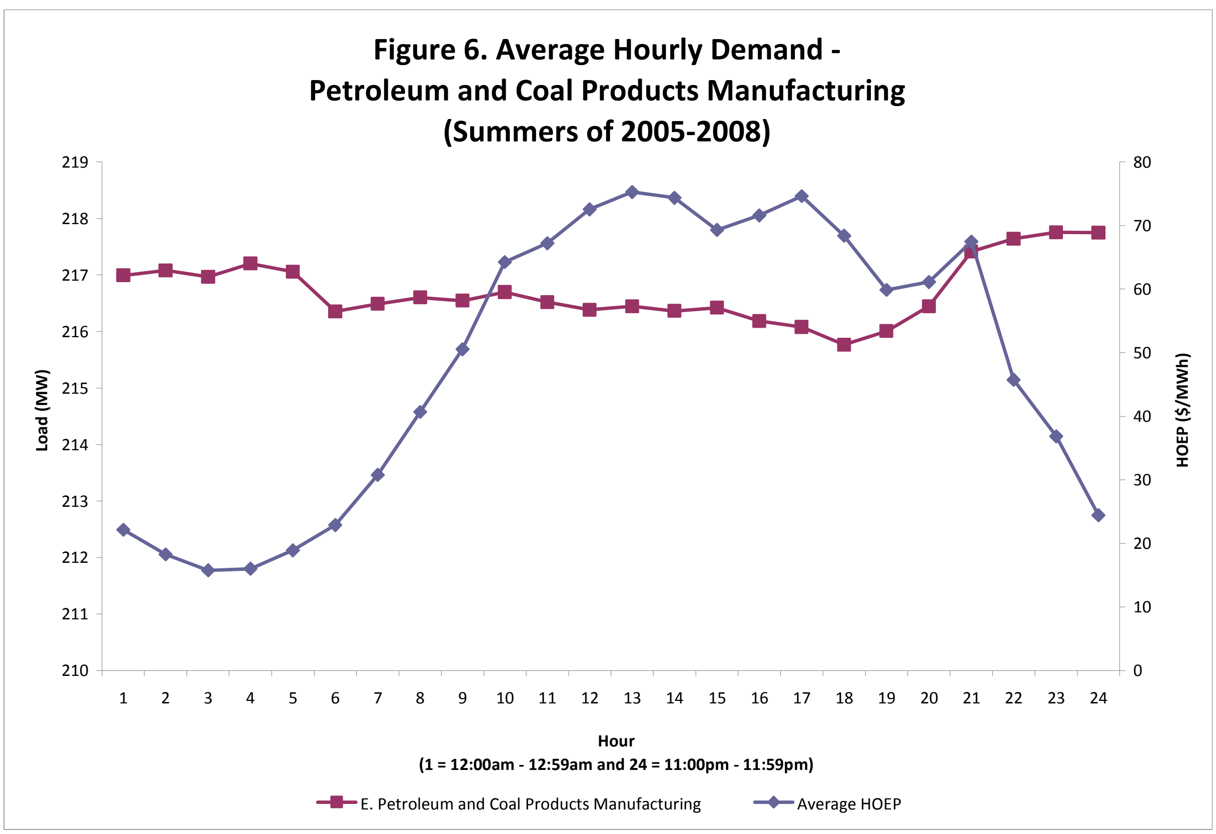


Figure 6. Average Hourly Demand -
Petroleum and Coal Products Manufacturing
(Summers of 2005-2008)
Load (MW)
HOEP ($/MWh)
219
218
217
216
215
214
213
212
211
210
80
70
60
50
40
30
20
10
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
(1 = 12:00am - 12:59am and 24 = 11:00pm - 11:59pm)
E. Petroleum and Coal Products Manufacturing
Average HOEP

Figure 7. Average Hourly Demand - Pulp, Paper and Paperboard Mills (Summers of 2005-2008)

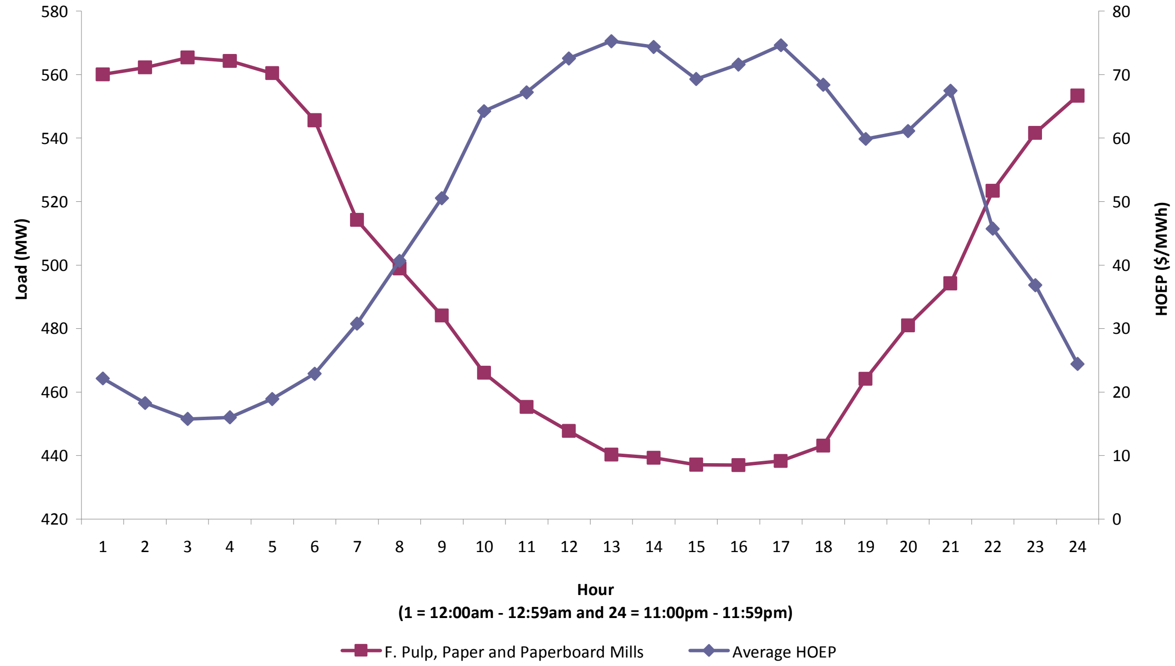


Figure 8. Average Hourly Demand - Electric Power Generation, Transmission and Distribution (Summers of 2005-2008)

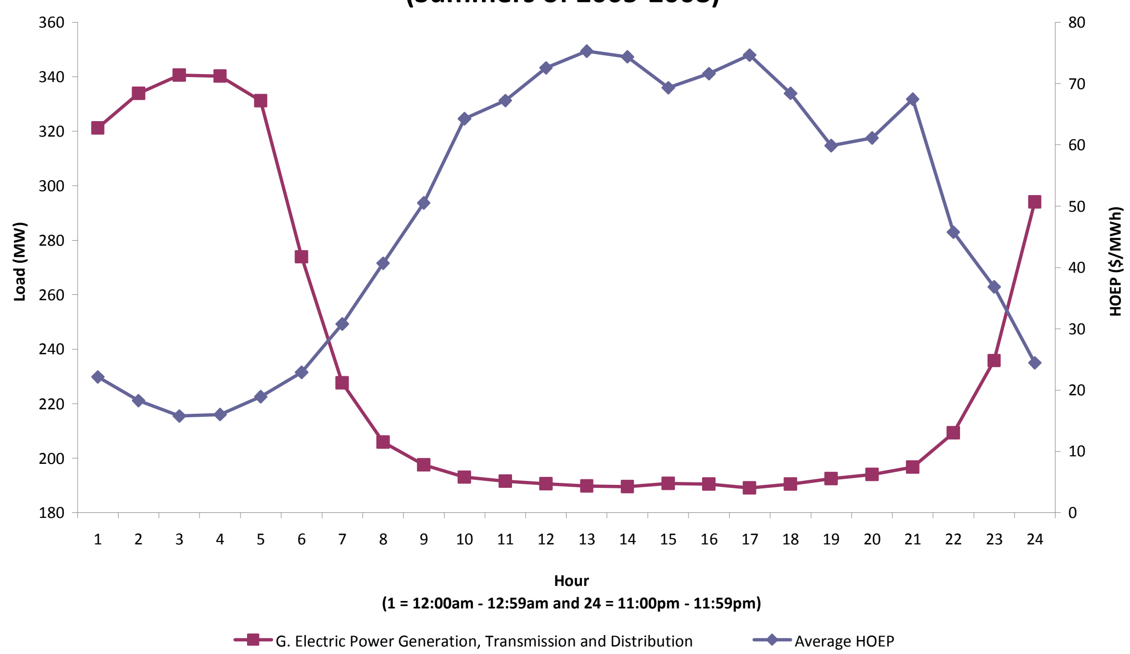


Table 1. Electricity Demand by Industry

	Summer of 2005	Summer of 2006	Summer of 2007	Summer of 2008
A. Total Industrial	8,549,586	8,196,697	7,577,013	7,717,774
As % of A				
B. Iron and Steel Mills and Ferro-Alloy Manufacturing	17.36%	19.28%	18.52%	20.56%
C. Metal Ore Mining	17.86%	17.52%	20.16%	20.18%
D. Motor Vehicle Manufacturing	6.13%	6.53%	5.97%	4.77%
E. Petroleum and Coal Products Manufacturing	7.20%	7.70%	8.57%	8.29%
F. Pulp, Paper and Paperboard Mills	23.43%	21.38%	17.68%	18.99%
G. Electric Power Generation, Transmission and Distribution	8.70%	8.88%	10.25%	8.94%
Ontario Demand	53,371,313	51,629,844	50,806,939	49,299,598
Industrial Demand as % of Ontario Demand	16.02%	15.88%	14.91%	15.65%

Table 2: Summary Statistics of Variables Used in Industry Demand Regressions

Years = 2005-2008

Variable	**Obs**	**Mean**	**Std. Dev.**	**Min**	**Max**
Total Industrial	984	2713.67	206.35	2161.17	3257.42
Iron and Steel Mills and Ferro-Alloy Manufacturing	984	512.80	56.11	299.67	647.50
Metal Ore Mining	984	512.26	52.52	276.08	605.92
Motor Vehicle Manufacturing	984	159.17	54.45	58.25	252.25
Petroleum and Coal Products Manufacturing	984	214.67	34.12	133.75	260.92
Pulp, Paper and Paperboard Mills	984	555.72	111.41	270.17	832.92
Electric Power Generation, Transmission and Distribution	984	248.91	56.80	146.83	409.33
HOEP	984	53.39	28.23	-1.96	234.61
Penn, New Jersey & Maryland LMP	984	63.19	33.45	14.06	356.42
New York North LMP	984	61.85	31.70	-40.36	406.09
Ont's Monthly Unemployment Rate	984	6.82	0.47	5.80	7.40
CAD-USD Exchange Rate	984	1.11	0.08	0.98	1.27
Holiday Dummy	984	0.02	0.15	0	1
Weekend Dummy	984	0.28	0.45	0	1

Summary Statistics of Variables Used in Price Regressions (Summer Months, Hourly Data)

Year = 2004-2007

Variable	**Obs**	**Mean**	**Std. Dev.**	**Min**	**Max**
New Price	11808	52.72	33.31	2.41	599.77
HHI	11795	5335.14	323.13	4315.00	6669.00
Ontario Demand	11808	17378.49	2975.63	11699.00	27005.00
Exports	11808	1345.61	562.59	0.00	3298.00
Imports	11808	883.75	546.57	0.00	4028.00
Coal	11808	3052.92	1337.89	0.00	6182.00
Gas	11808	1142.16	583.46	0.00	3542.00
Nuclear	11808	9378.39	871.63	0.00	11180.00
Hydro	11808	3733.38	1040.00	0.00	6101.00
Ont's Monthly Unemployment Rate	11808	6.90	0.50	5.80	7.50
CAD-USD Exchange Rate	11808	1.19	0.11	1.04	1.40
Weekend Dummy	11808	0.28	0.45	0	1
Holiday Dummy	11808	0.02	0.15	0	1
Day	11808	15.88	8.88	1	31

Table 3. Feasible Generalized Least Squares (FGLS) estimates by industry using month dummies

A. Total Industrial

	2005		2006		2007		2008	
ln(price)	-0.0755	c	-0.0812	c	-0.0563	c	-0.0462	c
	0.0069		*0.0080*		*0.0066*		*0.0048*	
lag(ln(price))	0.0683	c	0.0910	c	0.0690	c	0.0436	c
	0.0070		*0.0079*		*0.0071*		*0.0051*	
N	246		246		246		244	
Adj R^2	0.9674		0.9749		0.9639		0.9843	

B. Iron and Steel Mills and Ferro-Alloy Manufacturing

	2005		2006		2007		2008	
ln(price)	-0.0382	c	-0.0087		-0.0479	c	-0.0244	b
	0.0140		*0.0142*		*0.0132*		*0.0104*	
lag(ln(price))	0.0288	a	0.0655	c	0.0189		0.0138	
	0.0155		*0.0137*		*0.0131*		*0.0106*	
N	246		246		246		244	
Adj R^2	0.8084		0.8881		0.8301		0.9211	

C. Metal Ore Mining

	2005		2006		2007		2008	
ln(price)	-0.0566	c	-0.0640	c	-0.0255	c	-0.0175	c
	0.0081		*0.0110*		*0.0076*		*0.0062*	
lag(ln(price))	0.0154	a	0.0303	c	0.0306	c	0.0172	c
	0.0086		*0.0107*		*0.0075*		*0.0061*	
N	246		246		246		244	
Adj R^2	0.9272		0.8347		0.9194		0.9736	

D. Motor Vehicle Manufacturing

	2005		2006		2007		2008	
ln(price)	0.1929	c	0.2562	c	0.2520	c	0.1584	c
	0.0376		*0.0363*		*0.0275*		*0.0295*	
lag(ln(price))	0.1166	c	0.1441	c	0.1520	c	0.0770	c
	0.0412		*0.0410*		*0.0289*		*0.0294*	
N	246		246		246		244	
Adj R^2	0.3372		0.4223		0.5238		0.4829	

E. Petroleum and Coal Products Manufacturing

	2005		2006		2007		2008	
ln(price)	0.0063		-0.0013		-0.0017		0.0001	
	0.0058		*0.0073*		*0.0041*		*0.0030*	
lag(ln(price))	0.0148	c	0.0026		0.0023		0.0057	b
	0.0041		*0.0069*		*0.0046*		*0.0028*	
N	246		246		246		244	
Adj R^2	0.7634		0.8529		0.5816		0.9398	

F. Pulp, Paper and Paperboard Mills

	2005		2006		2007		2008	
ln(price)	-0.1699	c	-0.2464	c	-0.2166	c	-0.1284	c
	0.0136		*0.0144*		*0.0152*		*0.0146*	
lag(ln(price))	0.0889	c	0.1180	c	0.1108	c	0.0863	c
	0.0148		*0.0161*		*0.0179*		*0.0121*	
N	246		246		246		244	
Adj R^2	0.8147		0.7134		0.5409		0.7751	

G. Electric Power Generation, Transmission and Distribution

	2005		2006		2007		2008	
ln(price)	-0.3611	c	-0.4097	c	-0.2455	c	-0.2434	c
	0.0273		*0.0309*		*0.0235*		*0.0160*	
lag(ln(price))	0.3329	c	0.3896	c	0.2696	c	0.2018	c
	0.0274		*0.0274*		*0.0213*		*0.0173*	
N	246		246		246		244	
Adj R^2	0.8029		0.7756		0.7731		0.8887	

Notes: Peak hours are defined as 7 am to 6:59pm, while off peak hours are from 7 pm to 6:59 am the next day. The lag of ln(price) is ln(price in previous period). Specifically, when the dependent variable is demand during peak hours (7 am to 6:59pm), the previous period is 12 am to 6:59 am (off-peak hours). When demand is for off peak hours (7 pm to 6:59pm), the previous period is 7 am to 6:59pm (peak hours). Three observations are dropped in the year 2008 because average price in previous period is negative and hence log cannot be taken. Feasible Generalized Least Square (FGLS) corrects for Heteroskedasticity and AR(1) Serial Correlation (Prais-Winsten Method). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month dummies are included in the model but not shown in the table.

Table 4. Feasible Generalized Least Squares (FGLS) estimates by industry – not using month dummies, but other covariates

A. Total Industrial

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.0688	c	-0.0793	c	-0.0494	c	-0.0413	c
	0.0078		*0.0091*		*0.0076*		*0.0044*	
lag(ln(price))	0.0758	c	0.0929	c	0.0767	c	0.0487	c
	0.0082		*0.0089*		*0.0082*		*0.0048*	
ln(Ontario's	0.0683		-0.2091	c	-0.3112	c	-0.0074	
unemployment rate)	*0.1554*		*0.0500*		*0.0948*		*0.1098*	
ln(CAD-US	0.0991		0.6544		0.6561	b	0.3349	a
exchange rate)	*0.4289*		*0.5274*		*0.3244*		*0.2003*	
holiday	-0.0064		-0.0101		0.0256	a	0.0057	
	0.0191		*0.0148*		*0.0154*		*0.0162*	
weekend	0.0171	b	0.0106	a	0.0257	c	-0.0043	
	0.0077		*0.0058*		*0.0070*		*0.0058*	
N	246		246		246		244	
Adj R^2	0.9711		0.9760		0.9662		0.9860	

B. Iron and Steel Mills and Ferro-Alloy Manufacturing

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.0335	b	-0.0175		-0.0458	c	-0.0295	c
	0.0147		*0.0156*		*0.0150*		*0.0102*	
lag(ln(price))	0.0337	b	0.0574	c	0.0218		0.0088	
	0.0165		*0.0153*		*0.0146*		*0.0106*	
ln(Ontario's	0.0511		-0.2380	a	-0.9282	c	-1.0204	c
unemployment rate)	*0.2398*		*0.1372*		*0.2149*		*0.2812*	
ln(CAD-US	1.2624	a	-0.7725		0.9770		0.9161	a
exchange rate)	*0.7294*		*1.0645*		*0.7174*		*0.5004*	
holiday	-0.0201		-0.0458	a	0.0245		0.0046	
	0.0312		*0.0254*		*0.0440*		*0.0335*	
weekend	0.0120		-0.0250	b	0.0252	a	-0.0193	a
	0.0149		*0.0104*		*0.0141*		*0.0110*	
N	246		246		246		244	
Adj R^2	0.8104		0.8910		0.8333		0.9218	

C. Metal Ore Mining

	2005	2006	2007	2008
ln(price)	-0.0476 c	-0.0494 c	-0.0176 b	-0.0148 b
	0.0086	*0.0123*	*0.0077*	*0.0064*
lag(ln(price))	0.0244 b	0.0455 c	0.0390 c	0.0198 c
	0.0094	*0.0118*	*0.0078*	*0.0063*
ln(Ontario's	0.0379	-0.4169 b	0.0879	0.0493
unemployment rate)	*0.2044*	*0.1715*	*0.1643*	*0.1933*
ln(CAD-US	0.5052	0.5985	0.5718	-0.4708
exchange rate)	*0.7478*	*1.2057*	*0.6395*	*0.3795*
holiday	0.0008	-0.0114	-0.0055	0.0005
	0.0195	*0.0153*	*0.0190*	*0.0141*
weekend	0.0191 b	0.0242 b	0.0163 b	0.0098
	0.0077	*0.0111*	*0.0073*	*0.0067*
N	246	246	246	244
Adj R^2	0.9167	0.8456	0.9212	0.9737

	2005	2006	2007	2008
ln(price)	0.1369 c	0.1700 c	0.2072 c	0.1211 c
	0.0424	*0.0409*	*0.0327*	*0.0300*
lag(ln(price))	0.0611	0.0569	0.1033 c	0.0406
	0.0451	*0.0426*	*0.0336*	*0.0301*
ln(Ontario's	-1.2231	-0.5606	-0.6700	-1.3919
unemployment rate)	*0.8218*	*0.4212*	*0.4771*	*1.0092*
ln(CAD-US	-2.1215	-1.8422	3.5880 b	0.1512
exchange rate)	*2.3531*	*2.2282*	*1.7263*	*1.8917*
holiday	-0.0557	-0.0977	-0.0395	-0.0399
	0.0430	*0.0686*	*0.0399*	*0.0559*
weekend	-0.1458 c	-0.1839 c	-0.1141 c	-0.1608 c
	0.0246	*0.0287*	*0.0250*	*0.0193*
N	246	246	246	244
Adj R^2	0.3673	0.4809	0.5587	0.5379

E. Petroleum and Coal Products Manufacturing

	2005	2006	2007	2008
ln(price)	0.0055	0.0013	-0.0032	-0.0002
	0.0061	*0.0090*	*0.0045*	*0.0034*

lag(ln(price))	0.0138 [c]	0.0059	0.0010	0.0051 [a]
	0.0045	*0.0083*	*0.0051*	*0.0030*
ln(Ontario's	-0.0700	-0.0407	0.0371	0.4799 [c]
unemployment rate)	*0.0858*	*0.0635*	*0.0886*	*0.0780*
ln(CAD-US	1.2177 [b]	-1.0699	-0.2447	-0.7172
exchange rate)	*0.4764*	*0.7650*	*0.3105*	*0.8860*
holiday	-0.0033	-0.0064	-0.0012	0.0013
	0.0082	*0.0122*	*0.0030*	*0.0041*
weekend	-0.0013	0.0039	-0.0029	-0.0016
	0.0034	*0.0049*	*0.0030*	*0.0027*
N	246	246	246	244
Adj R^2	0.7539	0.7708	0.5301	0.9254

F. Pulp, Paper and Paperboard Mills

	2005	**2006**	**2007**	**2008**
ln(price)	-0.1362 [c]	-0.2165 [c]	-0.1578 [c]	-0.1034 [c]
	0.0140	*0.0145*	*0.0141*	*0.0117*
lag(ln(price))	0.1227 [c]	0.1355 [c]	0.1703 [c]	0.1103 [c]
	0.0143	*0.0133*	*0.0189*	*0.0101*
ln(Ontario's	-0.4873 [b]	0.1250 [b]	-0.0349	0.2351
unemployment rate)	*0.1970*	*0.0535*	*0.1260*	*0.2009*
ln(CAD-US	-0.8688	1.6295 [c]	0.6351	0.3375
exchange rate)	*0.5522*	*0.5468*	*0.4412*	*0.3606*
holiday	0.0500 [a]	0.0454 [a]	0.1733 [c]	0.0649 [a]
	0.0297	*0.0241*	*0.0192*	*0.0332*
weekend	0.0771 [c]	0.1114 [c]	0.1467 [c]	0.0587 [c]
	0.0149	*0.0091*	*0.0165*	*0.0146*
N	246	246	246	244
Adj R^2	0.8246	0.7263	0.5926	0.7854

G. Electric Power Generation, Transmission and Distribution

	2005	**2006**	**2007**	**2008**
ln(price)	-0.3281 [c]	-0.4064 [c]	-0.2245 [c]	-0.2250 [c]
	0.0252	*0.0375*	*0.0242*	*0.0146*
lag(ln(price))	0.3635 [c]	0.3959 [c]	0.2923 [c]	0.2206 [c]

	0.0245		*0.0332*		*0.0228*		*0.0161*	
ln(Ontario's	0.3435		-0.6120	c	-0.3112		0.0341	
unemployment rate)	*0.3137*		*0.1760*		*0.2683*		*0.3769*	
ln(CAD-US	-3.4060	c	3.5540	a	0.1089		0.8860	
exchange rate)	*0.9495*		*1.9006*		*0.8931*		*0.7223*	
holiday	0.0186		0.0300		0.1007		0.0180	
	0.0782		*0.0600*		*0.0636*		*0.0681*	
weekend	0.0862	c	0.0638	b	0.0618	b	0.0101	
	0.0273		*0.0279*		*0.0258*		*0.0233*	
N	246		246		246		244	
Adj R^2	0.7962		0.7835		0.7756		0.8943	

Notes: Peak hours are defined as 7 am to 6:59pm, while off peak hours are from 7 pm to 6:59 am the next day. The lag of ln(price) is ln(price in previous period). Specifically, when the dependent variable is demand during peak hours (7 am to 6:59pm), the previous period is 12 am to 6:59 am (off-peak hours). When demand is for off peak hours (7 pm to 6:59 am), the previous period is 7 am to 6:59pm (peak hours). Three observations are dropped in the year 2008 because average price in previous period is negative and hence log cannot be taken. Feasible Generalized Least Square (FGLS) corrects for Heteroskedasticity and AR(1) Serial Correlation (Prais-Winsten Method). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month dummies are not included in this model.

Table 5. Instrumental Variables (IV) estimates

First Stage IV Regression

	2005		2006		2007		2008	
lag(ln(price))	0.0689	a	0.0226		0.0368		0.0653	
	0.0400		*0.0446*		*0.0471*		*0.0507*	
ln(ont's unemployment rate)	0.0598		-0.8708	c	0.1814		-0.4249	
	0.4586		*0.1543*		*0.5773*		*0.8051*	
ln(cad-usd exchange rate)	4.6545	c	0.3178		-1.0203		1.2647	
	1.2891		*1.6664*		*1.6094*		*1.4444*	
holiday dummy	-0.1034	c	-0.0354		-0.0468		-0.2144	
	0.0272		*0.0859*		*0.1189*		*0.1652*	
weekend dummy	-0.0283		-0.0051		-0.1293	a	-0.1689	c
	0.0462		*0.0362*		*0.0633*		*0.0563*	
ln(PJM price)	0.5683	c	0.56278	c	0.67424	c	0.87802	c
	0.07663		*0.04839*		*0.06992*		*0.08344*	
ln(NYN price)	0.33498	c	0.17408	a	0.14752	b	0.05615	
	0.10817		*0.09921*		*0.06097*		*0.04113*	
N	245		244		246		230	
Adj R^2	0.6427		0.6776		0.5704		0.6142	
Test of Instrument Relevence								
H0: ln(PJM price)=0 and ln(NYN price)=0								
F statistic	171.094	c	228.353	c	115.693	c	93.4848	c

Second Stage IV Regression

A. Total Industrial

	2005		2006		2007		2008	
ln(price)	-0.0743	c	-0.0904	c	-0.0691	c	-0.0455	c
	0.0060		*0.0095*		*0.0091*		*0.0043*	
lag(ln(price))	0.0734	c	0.0922	c	0.0704	c	0.0462	c
	0.0059		*0.0080*		*0.0065*		*0.0045*	
ln(ont's unemployment rate)	0.0704		-0.2243	c	-0.3415	c	-0.0506	
	0.0812		*0.0286*		*0.0475*		*0.0900*	
ln(cad-usd exchange rate)	-0.2163		1.0853	c	0.4512	b	0.3764	c

	2005		2006		2007		2008	
	0.1985		*0.4199*		*0.2075*		*0.1145*	
holiday dummy	-0.0172		-0.0181		0.0590	c	0.0170	
	0.0218		*0.0115*		*0.0096*		*0.0208*	
weekend dummy	0.0129		0.0059		0.0176	c	-0.0069	
	0.0090		*0.0068*		*0.0063*		*0.0070*	
N	245		244		246		230	
Adj R^2	0.3553		0.5090		0.4919		0.4428	

B. Iron and Steel Mills and Ferro-Alloy Manufacturing

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.0675	c	-0.0465	b	-0.0742	c	-0.0449	c
	0.0170		*0.0218*		*0.0160*		*0.0125*	
lag(ln(price))	0.0264	b	0.0488	c	0.0122		-0.0055	
	0.0133		*0.0173*		*0.0180*		*0.0099*	
ln(ont's unemployment rate)	-0.0541		-0.2779	c	-1.0111	c	-1.1127	c
	0.1892		*0.0689*		*0.1785*		*0.2086*	
ln(cad-usd exchange rate)	0.6635		0.3214		0.6739		1.1027	c
	0.6112		*0.7485*		*0.4292*		*0.3782*	
holiday dummy	-0.0851	b	-0.0716		0.0943	b	-0.0018	
	0.0339		*0.0464*		*0.0432*		*0.0542*	
weekend dummy	0.0043		-0.0430	b	0.0231		-0.0152	
	0.0164		*0.0189*		*0.0156*		*0.0171*	
N	245		244		246		230	
Adj R^2	0.0412		0.1396		0.3920		0.2278	

C. Metal Ore Mining

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.0429	c	0.0376		0.0244		-0.0369	c
	0.0122		*0.0303*		*0.0219*		*0.0085*	
lag(ln(price))	0.0199	b	0.1158	c	0.0778	c	0.0056	
	0.0102		*0.0262*		*0.0117*		*0.0071*	
ln(ont's unemployment rate)	0.7060	c	-0.3249	c	0.1859		-0.0025	
	0.1271		*0.1168*		*0.1563*		*0.1579*	
ln(cad-usd exchange rate)	-0.1164		-0.5870		1.9106	c	-0.3511	
	0.3676		*1.2596*		*0.4674*		*0.2619*	

holiday dummy	0.0308		0.0332		0.0294		0.0056	
	0.0269		*0.0334*		*0.0351*		*0.0117*	
weekend dummy	0.0249		0.0622	a	0.0548	c	0.0091	
	0.0178		*0.0323*		*0.0192*		*0.0117*	
N	245		244		246		230	
Adj R^2	0.1596		0.0856		0.1424		0.0618	

D. Motor Vehicle Manufacturing

	2005		**2006**		**2007**		**2008**	
ln(price)	0.1979	c	0.3197	c	0.2772	c	0.1029	c
	0.0452		*0.0586*		*0.0488*		*0.0306*	
lag(ln(price))	0.0082		0.1378	c	0.0977	c	0.0052	
	0.0376		*0.0506*		*0.0300*		*0.0308*	
ln(ont's unemployment rate)	-1.3455	c	-0.8533	c	-1.5826	c	-2.2335	c
	0.4715		*0.2760*		*0.5104*		*0.6533*	
ln(cad-usd exchange rate)	-1.6441		-0.2877		2.6817	c	2.0517	a
	1.6374		*2.3511*		*0.9866*		*1.2066*	
holiday dummy	-0.2861	c	-0.1972	b	-0.2369		-0.1110	
	0.0423		*0.0839*		*0.1573*		*0.1007*	
weekend dummy	-0.4264	c	-0.4085	c	-0.3126	c	-0.4580	c
	0.0511		*0.0490*		*0.0584*		*0.0368*	
N	245		244		246		230	
Adj R^2	0.3536		0.4959		0.4800		0.4814	

E. Petroleum and Coal Products Manufacturing

	2005		**2006**		**2007**		**2008**	
ln(price)	0.1363	c	-0.0839	b	-0.1878	c	0.0504	c
	0.0249		*0.0362*		*0.0428*		*0.0113*	
lag(ln(price))	0.0725	c	-0.0405		-0.1246	c	0.0478	c
	0.0225		*0.0275*		*0.0244*		*0.0083*	
ln(ont's unemployment rate)	1.2624	c	-0.8562	c	-0.8770	c	2.3973	c
	0.4509		*0.0836*		*0.2367*		*0.2196*	
ln(cad-usd exchange rate)	5.0618	c	6.6329	c	-1.7596	b	2.3898	c
	0.5995		*1.2276*		*0.7874*		*0.1653*	
holiday dummy	-0.0591	a	-0.0764	c	-0.0077		0.0629	c

	0.0353		*0.0159*		*0.0968*		*0.0152*	
weekend dummy	0.0444		-0.0021		-0.0928	a	0.0276	
	0.0345		*0.0274*		*0.0519*		*0.0194*	
N	245		244		246		230	
Adj R^2	0.1358		0.2514		0.0925		0.6808	

F. Pulp, Paper and Paperboard Mills

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.1552	c	-0.2545	c	-0.1832	c	-0.1084	c
	0.0122		*0.0166*		*0.0192*		*0.0129*	
lag(ln(price))	0.1204	c	0.1399	c	0.1676	c	0.1087	c
	0.0091		*0.0137*		*0.0157*		*0.0093*	
ln(ont's unemployment rate)	-0.5376	c	0.1203	b	-0.0215		0.2069	
	0.1404		*0.0565*		*0.1181*		*0.1344*	
ln(cad-usd exchange rate)	-1.2060	c	2.0204	c	0.5216		0.2877	
	0.3671		*0.5903*		*0.4243*		*0.2828*	
holiday dummy	0.0469		0.0295		0.1677	c	0.0534	b
	0.0382		*0.0203*		*0.0156*		*0.0242*	
weekend dummy	0.0784	c	0.1036	c	0.1374	c	0.0558	c
	0.0119		*0.0087*		*0.0134*		*0.0145*	
N	245		244		246		230	
Adj R^2	0.4712		0.6851		0.5836		0.4840	

G. Electric Power Generation, Transmission and Distribution

	2005		**2006**		**2007**		**2008**	
ln(price)	-0.4472	c	-0.5244	c	-0.3075	c	-0.2464	c
	0.0249		*0.0571*		*0.0295*		*0.0162*	
lag(ln(price))	0.3501	c	0.3702	c	0.2698	c	0.2200	c
	0.0242		*0.0356*		*0.0221*		*0.0193*	
ln(ont's unemployment rate)	0.4268	a	-0.6178	c	-0.2560		-0.0689	
	0.2586		*0.1489*		*0.1622*		*0.2601*	
ln(cad-usd exchange rate)	-4.4997	c	5.1415	c	-0.2481		0.8402	b
	0.6976		*1.6338*		*0.8849*		*0.3941*	
holiday dummy	0.0611		-0.0348		0.1775	c	0.1053	
	0.0819		*0.0520*		*0.0602*		*0.0918*	

weekend dummy	0.0716 [b]	0.0481 [a]	0.0275	0.0336
	0.0278	*0.0264*	*0.0222*	*0.0282*
N	245	244	246	230
Adj R^2	0.5900	0.5652	0.5129	0.6358

Notes: Peak hours are defined as 7 am to 6:59pm, while off peak hours are from 7 pm to 6:59 am the next day. The lag of ln(price) is ln(price in previous period). Specifically, when the dependent variable is demand during peak hours (7 am to 6:59pm), the previous period is 12 am to 6:59 am (off-peak hours). When demand is for off peak hours (7 pm to 6:59 am), the previous period is 7 am to 6:59pm (peak hours). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month dummies are not included in this model.

Table 6. FGLS estimation with all years pooled

	A.	**B.**	**C.**	**D.**	**E.**	**F.**	**G.**
ln(price)	-0.0536 [c]	-0.0341 [c]	-0.0256 [c]	0.1493 [c]	0.0008	-0.1404 [c]	-0.2566 [c]
	0.0036	*0.0072*	*0.0042*	*0.0179*	*0.0025*	*0.0072*	*0.0116*
Lag(ln(price))	0.0677 [c]	0.0224 [c]	0.0307 [c]	0.0593 [c]	0.0064 [c]	0.1309 [c]	0.3037 [c]
	0.0039	*0.0074*	*0.0042*	*0.0184*	*0.0023*	*0.0071*	*0.0121*
ln(Ont's unemployment	-0.1630 [c]	-0.4592 [c]	-0.1232	-0.8291 [c]	0.0565	0.0755	-0.1851 [a]
rate)	*0.0406*	*0.0841*	*0.1565*	*0.2877*	*0.0584*	*0.0513*	*0.1123*
ln(cad-usd	0.3739 [b]	0.9507 [c]	0.2276	0.0254	-0.2352	0.3837 [a]	-0.5084
exchange rate)	*0.1519*	*0.3398*	*0.4227*	*1.0619*	*0.3355*	*0.2063*	*0.3823*
holiday dummy	0.0053	-0.0124	0.0007	-0.0648 [b]	0.0000	0.0740 [c]	0.0695 [a]
	0.0101	*0.0146*	*0.0096*	*0.0253*	*0.0041*	*0.0184*	*0.0407*
weekend dummy	0.0115 [c]	-0.0038	0.0173 [c]	-0.1524 [c]	-0.0003	0.0967 [c]	0.0628 [c]
	0.0036	*0.0066*	*0.0043*	*0.0119*	*0.0017*	*0.0073*	*0.0138*
N	982	982	982	982	982	982	982
Adj R^2	0.9720	0.8734	0.9194	0.4955	0.7735	0.7934	0.7529

Notes: Peak hours are defined as 7 am to 6:59pm, while off peak hours are from 7 pm to 6:59 am the next day. The lag of ln(price) is ln(price in previous period). Specifically, when the dependent variable is demand during peak hours (7 am to 6:59pm), the previous period is 12 am to 6:59 am (off-peak hours). When demand is for off peak hours (7 pm to 6:59 am), the previous period is 7 am to 6:59pm (peak hours). Three observations are dropped in the year 2008 because average price in previous period is negative and hence log cannot be taken. Feasible Generalized Least Square (FGLS) corrects for Heteroskedasticity and AR(1) Serial Correlation (Prais-Winsten Method). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month dummies are not included in this model. The estimates are obtained by pooling all data from 2005-2008. Year dummies (base year 2008) are included in the model but not shown in the table. Finally, A=Total Industrial, B=Iron and Steel Mills and Ferro-Alloy Manufacturing, C = Metal Ore Mining, D = Motor Vehicle Manufacturing, E = Petroleum and Coal Products Manufacturing, F = Pulp, Paper and Paperboard Mills, G = Electric Power Generation, Transmission and Distribution.

Table 7. FGLS estimates during peak hours

	2005		2006		2007	
Herfinahl Hirschman Index	-0.02087	c	-0.0077	a	-0.04579	c
	0.0079		*0.004565*		*0.005433*	
Ontario Demand	0.019805	c	0.024611	c	0.016288	c
	0.00324		*0.002673*		*0.003316*	
Exports	0.01677	c	0.021947	c	0.016157	c
	0.004789		*0.003142*		*0.003663*	
Imports	-0.00924	b	-0.01727	c	-0.0123	c
	0.004566		*0.003189*		*0.003435*	
Coal	-0.01042	b	-0.01574	c	-0.00322	
	0.004241		*0.003404*		*0.003865*	
Gas	0.006013		0.000199		-0.00066	
	0.004581		*0.006438*		*0.004339*	
Nuclear	-0.02442	c	-0.02429	c	-0.01862	c
	0.005014		*0.003683*		*0.003948*	
Hydro	0.009711	a	-0.00874	b	0.006302	
	0.005776		*0.004157*		*0.004323*	
Exchange rate	249.6552	a	84.19145		60.57152	
	140.7177		*178.0452*		*79.20249*	
Weekend	32.8638	c	27.1233	c	30.41514	c
	4.436903		*6.034897*		*2.926984*	
Holiday	22.97404	c	19.63368	c	32.83669	c
	6.259205		*6.413037*		*4.426336*	
Day	0.519933	c	0.021466		0.133247	
	0.171532		*0.124395*		*0.085083*	
N	1599		1598		1599	
Adjusted R^2	0.278497		0.377733		0.323542	

Notes: Peak hours are defined as 7 am to 6:59pm,. The data are hour specific. Feasible Generalized Least Square (FGLS) corrects for Heteroskedasticity and AR(1) Serial Correlation (Prais-Winsten Method). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month and hour dummies are included in this model but not reported.

Table 8. FGLS estimates –off peak hours

	2005		2006		2007	
Herfindahl Hirschman Index	0.005632		0.006452	b	0.002361	
	0.00513		*0.002754*		*0.003244*	
Ontario demand	0.012697	c	0.021109	c	0.00782	c
	0.002731		*0.002783*		*0.002733*	
Exports	0.008985	c	0.019132	c	0.007857	b
	0.003173		*0.003049*		*0.003058*	
Imports	-0.00894	a	-0.01468	c	-0.00307	
	0.004613		*0.003*		*0.003012*	
Coal	-0.0083	c	-0.01594	c	-0.00281	
	0.002976		*0.002945*		*0.003109*	
Gas	0.017181	c	0.001777		0.005233	
	0.006126		*0.004905*		*0.003967*	
Nuclear	-0.01541	c	-0.01936	c	-0.00903	c
	0.003351		*0.00298*		*0.003074*	
Hydro	-0.00678		-0.01825	c	-0.00514	
	0.004323		*0.003*		*0.003149*	
Exchange rate	237.2791	c	94.36653		22.72758	
	86.72347		*66.54274*		*56.88866*	
Weekend	12.17091	c	9.399056	c	4.268227	c
	2.09121		*1.427448*		*1.143001*	
Holiday	9.650554	b	4.329244		6.355335	c
	4.628665		*2.987563*		*2.443723*	
Day	0.1082		-0.14232	b	0.179523	c
	0.123606		*0.061053*		*0.052105*	
N	1353		1348		1353	
Adjusted R2	0.652848		0.737947		0.742538	

Notes: Off peak hours are defined as 7 pm to 6:59 am,. The data are hour specific. Feasible Generalized Least Square (FGLS) corrects for Heteroskedasticity and AR(1) Serial Correlation (Prais-Winsten Method). Standard errors in *italic*. a, b and c indicate significant at 10%, 5% and 1% level respectively. Month and hour dummies are included in this model but not reported.