EXAMINING THE EXISTENCE OF MARKET POWER IN NOVA SCOTIA'S OFFSHORE NATURAL GAS INDUSTRY

by

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DEDICATION PAGE

This work is dedicated to Layla.

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ABSTRACT

This thesis examines the market structure of Nova Scotia's offshore natural gas market. For the period of study, there are two offshore producers who extract natural gas for sale to one provincial distributor. The distributor, Heritage Gas, then faces demand from residential, commercial, and industrial consumers within Nova Scotia. Using price and quantity data provided by Heritage Gas and Statistics Canada respectively, I estimate the distributor's demand from the offshore producers, as well as the demand from residential, commercial, and industrial customers in the province. Using these results, I determine whether the offshore producer or the distributor appear to practice any degree of market power. I find some evidence that suggests the latter on the part of the offshore producers, and evidence that the distributor practices price mark-ups in the commercial market. The existence of market power would suggest that significant wealth transfers have taken place from the stock of provincial natural gas wealth to corporations based outside Nova Scotia. This is a matter of interest because that would imply that the majority of benefits from that wealth are enjoyed outside the province. Though I do not find strong definitive evidence of monopoly power in all markets, some of my results suggest some degree of market power for both the producers and distributor.

LIST OF ABBREVIATIONS USED

SOEP	Sable Offshore Energy Project
HG	Heritage Gas
OS	Offshore
MC	Marginal Cost
MR	Marginal Revenue
TR	Total Revenue
AR	Average Revenue
AC	Average Cost

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Chapter 1. Introduction

This paper analyzes the market structure of the natural gas industry in Nova Scotia using a model of non-renewable resource extraction and a model of a profit-maximizing distributor. Using these models, I determine whether either the offshore producers or the Nova Scotia distributor of natural gas practice monopoly power in the industry, and how this affects consumers' welfare relative to a socially optimal, perfectly competitive market regime. Welfare is measured as the sum of consumer and producer surplus.

The outline of the paper is as follows. Chapter 2 discusses previous studies that have been done in relations to natural gas, as well as Hotelling's theory. Chapter 3 provides relevant background information on offshore drilling, and Nova Scotia's natural gas industry. Chapter 4 outlines Nova Scotia's market structure, the model of non-renewable resource extraction, and discusses Harold Hotelling's 1931 model, as well as a model of a profit-maximizing distributor. Chapter 5 concerns the data used for the analysis. Chapter 6 outlines my methodology, followed by Chapter 7 in which I present my results. Finally, Chapter 8 provides a discussion of the study.

Chapter 2. Literature Review

Many authors have worked on Hotelling's original model of resource extraction. Chapman 1993 accounts for population and world income growth by modelling outward shifting demand. Fluctuating demand is also examined by Amundsen (1991) who shows that the installation of underground natural gas storage systems lowers the cost of producing by smoothing production over alternating demand cycles.

Several studies also empirically test the assumptions of Hotelling's model. These studies have often found that the original model does not tend to explain the actual behaviour of resource prices, or firms. Young (1992) examines various cost specifications to determine if certain cost functions result in an adherence to Hotelling's predictions. Using data from the Canadian copper mining industry, she finds that cost specifications do not lead to adherence to Hotelling's predictions. Similar research from Farrow (1985) uses proprietary data from an anonymous metal ore-mining firm to compute the shadow price and uses this to compare the theoretical and actual price paths. Again, the data do not adhere to what theory predicts.

Other studies examine the cost of natural gas distribution. Guldmann (1983) outlines three types of marginal costs faced by natural gas distribution firms: marginal customer cost (cost to hook up an additional customer to the distribution system), marginal capacity cost (cost of constructing the distribution system with the capacity to meet the last unit of peak demand), and marginal commodity cost (cost of supplying an additional unit of gas, i.e., the wholesale price) (Guldmann, 1983). The first two relate to capital costs of the firm, and, for existing customers, once installed, do not seem to vary depending on units of gas consumed by a customer each period. Using data from gas and electric utility firms in New York state and Ohio, Guldmann models cost functions for the firms. He finds an insignificant effect of non-residential capacity on total cost for one firm and an insignificant effect of residential capacity for the other utility firm (Guldmann, 1983). The variation in these two results may be due to differences in geography and population density. In a similar work by Bernard, Bolduc, and Hardy (1998), data from a Quebec natural gas utility are used. These authors find that the effect on total cost of peak demand is insignificant for all customer classes.

Some studies examine the effects of various market structures on the efficiency of the natural gas industry. Polo and Scarpa (2013) find that even in a liberalized retail market, take-or-pay clauses between producers and wholesalers disincentivize face-to-face competition and may lead to monopoly pricing. Spieker (2013) uses a game theoretic model to examine the impact of market power on the natural gas industry. Spieker finds that prices are increasing in an oligopoly as firms set a price that includes a mark-up on top of their marginal costs, and as a result, natural gas demand declines, as does production. Under competition however, production is greater, as firms with existing capacities need only cover short run marginal costs.

Chapter 3. Background

3.1 Natural Gas

Like oil and coal, natural gas is a fossil fuel, but is cleaner burning than the first two (Bahadori, 2014). Fossil fuels are formed from the decayed remains of organic material that are millions of years old, which have broken down into hydrocarbons. Natural gas is the lightest of these hydrocarbons. It is colourless, odourless, and primarily composed of methane, which is highly flammable. After being extracted from the ground, the gas can be converted into energy for consumption.

The formation of natural gas can occur in three ways. Thermogenic methane is formed when organic particles become trapped under layers of mud and sediment for millions of years (Bahadori, 2014). The high pressure of the sediment compresses the organic matter and, in combination with the increasingly high temperatures that occur closer to the Earth's center, breaks down the carbon bonds of the organic matter. This same process creates oil, and this is why oil and natural gas deposits are usually found together. However, at lower temperatures closer to the Earth's surface, more oil is produced relative to gas. Meanwhile, higher temperatures deeper beneath the surface produce more gas than oil, and extremely deep deposits are typically composed of pure methane (Bahadori, 2014).

Biogenic processes can also produce methane. Methanogens are microorganisms that chemically break down organic matter and in so doing, produce methane. These microorganisms are found in the intestines of animals, but can also be found in areas void of oxygen that are close to the surface of the Earth. Because of these methanogens' proximity to the Earth's surface, the methane produced rises easily from the ground into the atmosphere, and is not captured for energy consumption. However, in certain areas such as waste-containing landfills, these organisms may thrive, producing methane that can be trapped underground (Bahadori, 2014).

Finally, methane may also be produced through abiogenic processes. This occurs when hydrogen-rich gases and carbon found at extreme underground depths rise toward the surface, potentially reacting with other minerals to produce atmospheric compounds or elements such as nitrogen, carbon dioxide, oxygen. In the presence of high pressure, these will likely produce methane (Bahadori, 2014).

Once the gas is formed, it can be classified as either “conventional” or “unconventional” (Bahadori, 2014). Most oil and gas production since the industry’s beginning has been from conventional sources of natural gas. Conventional gas accumulations are easier and more economical to extract. The layers of the sediment (referred to as the source of the gas) fold and fault, which traps the hydrocarbons within the pores of what eventually becomes a highly porous and permeable rock, referred to as the reservoir. The reservoir can contain hydrocarbon gases, liquid hydrocarbons, and nonhydrocarbon gases, as well as aqueous solutions, depending on the physical and thermodynamic properties of the rock (Bahadori, 2014). The reservoir must be covered in a trap, an impermeable rock layer that prevents any gas or liquid from escaping. Because the gas is under high pressure within the rock, the drilling of a vertical well releases that pressure, and allows the gas to flow through the well to the surface where it is trapped for human use.

Unconventional natural gas is more difficult to define, but generally refers to gas deposits that are less concentrated and are dispersed over a greater area, and also require additional stimulation, extraction technology or methods to produce (Bahadori, 2014). This is because the gas is trapped within impermeable rock, and therefore is unable to accumulate into a conventional deposit. Because the gas cannot migrate, a typical vertical well does not release the gas and allow it to rise through the well to the surface (Bahadori, 2014). Therefore, in order for these deposits to be commercially viable, they require extraction methods such as horizontal drilling and hydraulic fracturing. Recent technological developments in these methods have dramatically increased the global supply of natural gas (Bahadori, 2014).

3.2 Offshore Natural Gas Drilling

Offshore natural gas drilling is the act of extracting natural gas (or other hydrocarbons) out of reservoirs beneath the surface of ocean floors, or other bodies of water, by way of a drill. Geological data are used to determine likely deposits of hydrocarbons. Once a potential location is found, firms assess whether it is economical to explore further, taking factors such as geological risk, exploratory drilling and capital costs, potential financial profit, and royalties into account. Exploratory drilling then takes place to confirm the existence and exact locations of natural gas reserves. Exploratory wells are typically drilled using moveable rigs, such as drilling barges, jack-up rigs, or submersible rigs for shallower water, or semisubmersible rigs, and drill ships for deeper bodies of water. Jack-up rigs have legs that are secured to the sea floor and are used at depths of up to 61 meters, while semisubmersible rigs float anchored to the sea floor and are used in exploratory drilling up to depths of 1219 meters. Finally, drilling ships are used up to depths of 2438 meters (Speight, 2014).

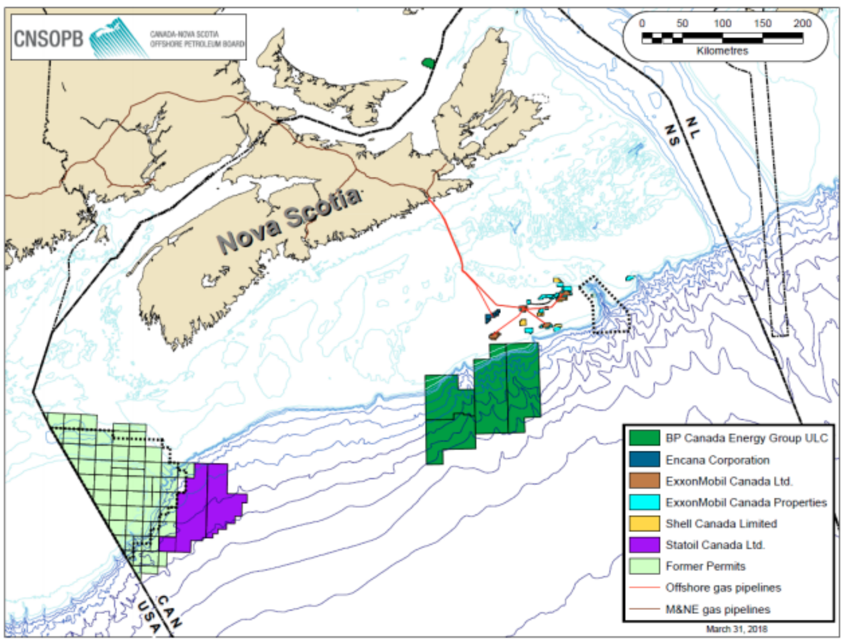
Once a reserve is confirmed by the exploratory drilling, a permanent (at least for the life of the drilling project), manned drilling platform is constructed that can accommodate over forty wells (Speight, 2014). These enormous structures are built to accommodate an above-sea-level facility, which typically contains equipment for various gas processing, as well as crew quarters. Sub-sea facilities are often present as well, which aid in the separation of sand and silt from the extracted hydrocarbons (Speight, 2014). If the pressure in the well does not remain high enough to release the gas at the necessary rate, then these subsea facilities will also use a pump mechanism to artificially lift the gas from the formation (Speight, 2014). The legs of the platform are either secured to the ocean floor or are semi submersible, air-filled legs that are anchored to the ocean floor, and are built to withstand the extreme weather that can occur at sea. Extraction continues until the reserve is depleted or other circumstances dictate its closure, at which time the production well must be decommissioned, as dictated by the Canada-Nova Scotia Offshore Petroleum Board. This process involves plugging the well and clearing away all infrastructure used in the production process.

3.3 Nova Scotia’s Offshore Natural Gas Industry

Until late 2018, there were two offshore natural gas projects producing in Nova Scotia: the Sable Offshore Energy Project (SOEP), operated by ExxonMobil Canada, and the Deep Panuke Offshore Gas Project, operated by Encana, both of which are currently in the process of decommissioning. Drilling took place off the Atlantic coast, near Sable Island, shown in Figure 1. The right to explore and produce on Nova Scotia’s offshore is awarded through a call for bids process authorized by the Canada-Nova Scotia Offshore Petroleum Board.

The Sable Offshore Energy Project began the production of natural gas in 1999 after receiving regulatory approval in 1997 (Canada-Nova Scotia Offshore Petroleum Board, 1997). The initial development of the Project involved six different natural gas fields. The initial reserves of these six fields combined were an estimated eighty-five thousand million cubic meters. At this initial reserve quantity, the project was expected to last about twenty-five years, subject to the discovery of new recoverable reserves, which would extend the life of the project. The initial proposal for Sable Offshore Energy Project (SOEP) involved 28 development wells. From these wells, the project was designed to extract raw gas at a rate of 14.4 million cubic meters per day,

Figure 1. Geography of Offshore Gas Fields

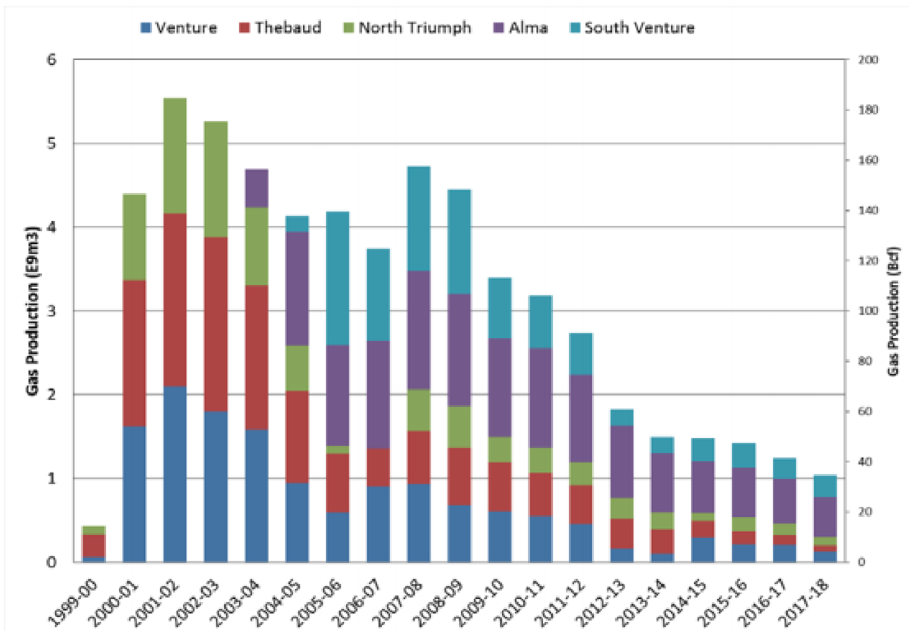


(Source: Canada-Nova Scotia Offshore Petroleum Board, 2018)

which would yield thirteen million cubic meters per day of marketable gas after processing. The project was designed to maintain this rate for thirteen years, after which time the extraction rate would decline for the final estimated twelve years of the Project's life (Canada-Nova Scotia Offshore Petroleum Board, 1997), making the total estimated life of the project twenty five years.

At the initially planned daily extraction rate, annual production should have been roughly 5256.0 million cubic meters for the first twelve years and then seen a steady decline (Canada-Nova Scotia Offshore Petroleum Board, 1997). However, actual production data indicate that annual production in 1999 was only about 0.5 billion cubic meters. Production then increased dramatically, peaking at 5500 million cubic meters per year by only 2002, after which annual production declined steadily, only peaking again significantly between 2006 and 2009. From 2009 onwards, production continued to decrease to its lowest in 2017 at just over one thousand million cubic meters (Canada-Nova Scotia Offshore Petroleum Board, 2018). Figure 2 shows the annual production in billions of cubic meters (E9m3) from the Sable Offshore Energy Project by gas field.

Figure 2. Sable Offshore Energy Project Annual Production

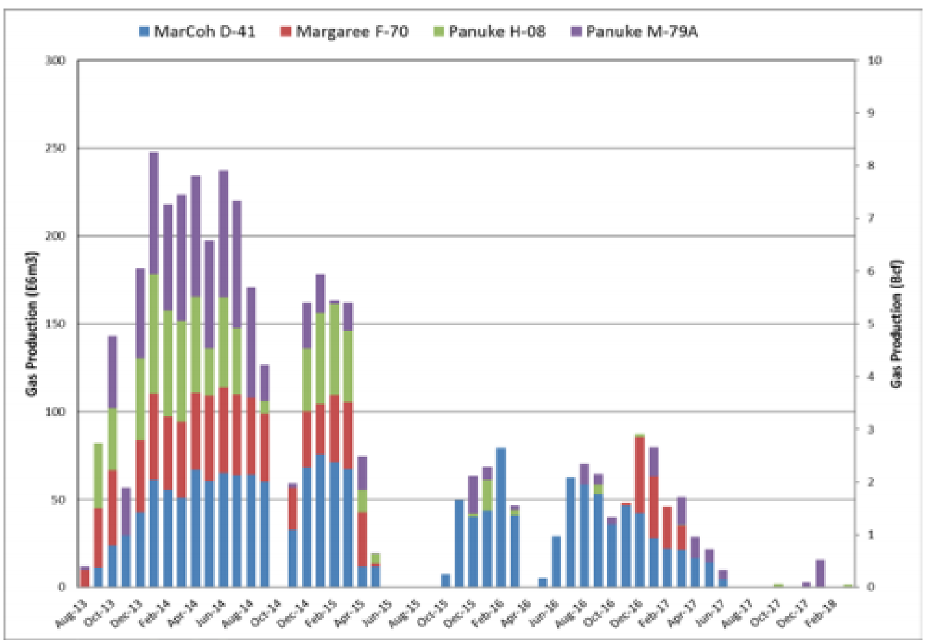


(Source: Canada-Nova Scotia Offshore Petroleum Board, 2018)

Though production for the Deep Panuke Project did not begin until 2013, the natural gas field had been discovered in 1998, beneath the previously exploited Cohasset and Panuke oil fields. The Deep Panuke reserve is classified as a sour gas, containing roughly 0.18% hydrogen sulphide, which means it requires additional processing to sweeten the gas (Canada-Nova Scotia Offshore Petroleum Board, 2007). From this reserve, it was expected at initial planning that the overall quantity of marketable natural gas ranged from 11 000 billion to 25 100 million cubic meters, with an expected project life of thirteen years, subject to additional discoveries of recoverable reserves (Canada-Nova Scotia Offshore Petroleum Board, 2007).

Monthly production from Deep Panuke was at its highest in January 2014, at approximately 250 million cubic meters (Canada Nova Scotia Offshore Petroleum Board, 2018). After September 2014 the project began seasonal production cycles. Extraction is at its highest during the winter months, and production ceases during the summer. In this way, the company captures a higher price during the colder season, when natural gas demand is higher (Encana, 2018). In the months October 2017 to March 2018, total monthly production was at its lowest since operations began, peaking at roughly 16.67 million cubic meters in January (Canada-Nova Scotia Offshore Petroleum Board, 2018). Figure 3 shows the monthly production from Deep Panuke by gas field in millions of cubic meters (E6m3). Once the gas is extracted from the offshore, it is transported via the pipeline to a processing plant in Goldboro, NS (National Energy Board, 2019). The gas is distributed through the Maritimes & Northeast Pipeline to Nova Scotia, New Brunswick, and to the northeast United States through an import/export interconnect in St Stephen, New Brunswick (National Energy Board, 2019). Though both producers have the ability to export Nova Scotian natural gas to markets in New Brunswick, and the Northeast US, by law, they are required to sufficiently meet demand in Nova Scotia before any excess supply may be exported (Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act, 1987).

Figure 3. Deep Panuke Monthly Production



(Source: Canada-Nova Scotia Offshore Petroleum Board, 2018)

Chapter 4. Market Structure

Nova Scotia's natural gas market involves three main agents, each with their own set of objectives. There are the two offshore producers, ExxonMobil Canada Ltd. and Encana, who extract the natural gas for sale on the market. They can decide to sell their gas to the Nova Scotia market, the U.S. market, or they can decide to leave stock in the ground for sale in a later period. The producers face the problem of profit maximization, subject to a finite amount of stock in the ground that they must ration through time in such a way that maximizes the benefits to the firm of the resource.

The sole Nova Scotian distributor, Heritage Gas Limited, buys the natural gas from the offshore producers, and distributes it throughout the province. Heritage Gas is a wholly owned, indirect subsidiary of AltaGas Canada Inc., a publically owned Canadian natural gas distribution company (Heritage Gas Limited, 2019). The distributor is granted franchise rights from the Nova Scotia Utility and Review Board, who regulate the delivery rates that Heritage Gas charges its customers. These rates are set by Heritage Gas, but must be submitted to the Review Board for approval. However, the board does not regulate the wholesale price of gas (Gas Distribution Act, 1997). Under section 22 of the Gas Distribution Act, the delivery charges must give consideration to several factors. These include (but are not limited to) public acceptability, "effectiveness in yielding total revenue requirements under the just and reasonable return standard" (Gas Distribution Act, 1997), revenue stability, competition, "fairness of the specific rates, tolls or charges in the apportionment of total costs of service among the different consumers," "efficiency of the rates, tolls or charges in discouraging wasteful use of service while promoting all justified types and amounts of use" (Gas Distribution Act, 1997). So, although the rates do give consideration to competition, they also give a significant degree of consideration to the distributor's total revenue and total costs.

Though Heritage Gas has access to natural gas from the US via the Maritimes & Northeast pipeline, Nova Scotian supply is given priority, so that American gas is imported only when local supply is insufficient. Therefore, they are not faced with concerns over finite stock, because they have access to natural gas supplied by the U.S. once the offshore stock is depleted. As a firm, they are also primarily concerned with profit maximization. Finally, there are the consumers of natural gas in Nova Scotia. There are three classes of consumers. Residential consumers demand natural gas primarily for home heating and typically require smaller volumes of gas each month. Commercial consumers are businesses or apartment complexes, which typically demand higher volumes. Then there are industrial consumers, who represent industrial firms who require large volumes of gas for the production of other goods or services. These three classes of consumers represent three different markets within Nova Scotia who demand a particular quantity at a particular price. The following sections outline a model of the distributor's and the offshore producers' behaviour respectively.

4.1 Nova Scotia Distributor: Model of a Profit Maximizing Firm Under Competition and Monopoly:

The following is a standard model of a profit-maximizing firm that does not face a finite stock constraint. The firm incurs a cost by purchasing inputs; it then distributes its product on the market at the exogenously determined, perfectly competitive price. A cost function of the form $C\big(Q(t)\big)$ is assumed. If the consumer market is competitive, then the firm acts as a price-taker, and is faced with the following profit maximization problem in any given time period:

$$\max \pi = P(t)Q(t) - C(Q) \tag{1}$$

The first order condition gives:

$$\frac{\partial \pi}{\partial Q(t)} = P(t) - \; MC = 0 \tag{2}$$

Therefore, under the assumed socially optimal condition of perfect competition, the market price should be equal to the distributor's marginal cost.

If the firm enjoys market power, then it no longer behaves as a price taker, and can increase its price above its marginal cost, as it does not face the same level of competition it would under a perfectly competitive market. The most extreme case is one of a monopoly. In this instance, the firm has access to the entire market. The price it charges is determined by the inverse market demand function given as:

$$P(Q) \tag{3}$$

Under a monopoly market, the firm's profit maximization problem becomes:

$$\max \pi = P(Q)Q(t) - C(Q) \tag{4}$$

The first order condition is therefore:

$$\frac{\partial \pi}{\partial Q(t)} = MR - MC = 0 \tag{5}$$

where MR is the firm's marginal revenue function.

Equation (5) shows that a monopolist maximizes profit by producing a quantity $Q(t)$ that equates the firm's marginal revenue with marginal cost, and then marks the price up to that quantity's corresponding price given the demand function.

4.2 Offshore Producers: Model of Non-Renewable Resource Extraction Under Competition and Monopoly:

The following section examines the problem of the offshore firms by modeling their behaviour under two different market regimes. The first is a competitive market, and the second is a monopoly market. In the monopoly case, the firm is the sole supplier of natural gas, and therefore enjoys a high degree of market power, and thus the ability to raise its price above the competitive level.

The following model considers a representative price-taking firm that has a fixed stock of a non-renewable resource at initial time $t = 0$, $x(0)$, which it will extract and sell in a competitive market (Gray 1914). At time $t \in [0, T]$, where T is the terminal time, the firm decides on a quantity to extract and supply to the market, $Q(t)$. To send $Q(t)$ to market, the firm faces an extraction cost, denoted by $C(Q(t))$. Because at this point the market is assumed to be competitive, the exogenous market price at time t is denoted by $P(t)$.

The firm maximizes the present value of the stream of net benefits from the resource by selecting the extraction path $Q^*(t)$ that satisfies the following optimization problem:

$$\int_0^T e^{-\delta t} \left[P(t)Q(t) - C(Q(t))\right] dt \tag{6}$$

subject to

$$\dot{x}(t) = -Q(t), \forall t \tag{7}$$

$$0 \leq Q(t), \forall t \tag{8}$$

$$x(0) \ given \tag{9}$$

Equation (7) is the equation of motion, which shows that the change in the stock with respect to time, $\dot{x}(t)$, is the negative of quantity extracted, while equation (8) dictates that the quantity extracted cannot be negative; δ is the firm's discount rate.

This problem can easily be represented as a current value Hamiltonian, where $\lambda(t)$ is the co-state variable, or shadow price, representing the marginal value of an additional unit of stock. Thus, the shadow price represents the opportunity cost of extracting a marginal unit of the stock, as the firm could instead leave the unit in the ground for future extraction. In the context of the offshore producers, however, the shadow price also represents the opportunity cost of selling a unit of gas in the Nova Scotia market instead of the US market. λ(t) therefore represents the value in US dollars of the marginal unit of gas in the US market. The following Hamiltonian is borrowed from Conrad and Clark 1987, pages 117-126:

$$\widetilde{\mathcal{H}}\big(t, Q(t), x(t), \lambda(t)\big) = P(t)Q(t) - C\big(Q(t)\big) - \lambda(t)Q(t) \tag{10}$$

The conditions of the Maximum Principle hold as follows. The maximum condition gives

$$\frac{\partial \widetilde{\mathcal{H}}}{\partial Q(t)} = P(t) - \frac{\partial C}{\partial Q(t)} - \lambda(t) = 0$$

$$\frac{\partial \widetilde{\mathcal{H}}}{\partial Q(t)} = P(t) - MC = \lambda(t). \tag{11}$$

That is, the firm maximizes its net benefits at any point in time by extracting up to the point where the net marginal value of a unit of the resource sold in the market is equal to its value in the ground. Equation (11) also shows that the competitive price is given by

$$P^*(t) = MC + \lambda(t)$$

The adjoint equation is

$$\dot{\lambda} - \delta\lambda = -\frac{\partial \widetilde{\mathcal{H}}}{\partial x(t)}$$

$$\dot{\lambda} - \delta\lambda = 0$$

which yields the result

$$\dot{\lambda} = \delta\lambda$$

$$\frac{\dot{\lambda}}{\lambda} = \delta \tag{12}$$

From equation (12), we know that the present value of the shadow price is equal over time, such that the value of the shadow price at time t is equal to the discounted value of the initial shadow price (at $t = 0$)

$$\lambda(t) = \lambda(0)e^{\delta t}. \tag{13}$$

Finally, the transversality condition,

$$\widetilde{\mathcal{H}}\big(T, Q(T), x(T), \lambda(T)\big) = P(T)Q(T) - C\big(Q(T)\big) - \lambda(T)Q(T) = 0, \tag{14}$$

dictates that by the termination of the project, there is no remaining benefit from extracting the resource.

The firm's optimal extraction path is obtained from these equations. From equations (14) and (11),

$$P(T)Q(T) - C\big(Q(T)\big) - [P(T) - MC]Q(T) = 0$$

$$-C\big(Q(T)\big) + MCQ(T) = 0$$

$$MCQ(T) = C\big(Q(T)\big)$$

$$MC = AC \tag{15}$$

This indicates that the firm extracts where average cost of extraction equals marginal cost, given this point represents the maximum distance between price and average cost, and consequently, the last shadow price is highest at this point. Equation (16) yields $Q(T)$. From (11) and (13),

$$\lambda(T) = P(T) - MC\big(Q(T)\big)$$

$$\lambda(t) = \lambda(0)e^{\delta t}$$

$$\lambda(T) = \lambda(0)e^{\delta T}$$

$$\lambda(0) = \lambda(T)e^{-\delta T}$$

$$\lambda(t) = \lambda(T)e^{-\delta(T-t)} \tag{16}$$

$$P(t) - MC = \lambda(T)e^{-\delta(T-t)} \tag{17}$$

Solving (17) for $Q(t)$ gives an expression for $Q^*(t)$ in terms of the shadow price, and distance in time from T, where $Q^*(t)$ represents the profit maximizing extraction path.

A general dynamic model under a monopoly is different. The firm is no longer a price taker and therefore, price is determined by the inverse demand curve $P(Q(t))$. The current value Hamiltonian, which is also taken from Conrad and Clark 1987 (pages 117-126), is now

$$\widetilde{\mathcal{H}} = P\big(Q(t)\big)Q(t) - C\big(Q(t)\big) - \lambda(t)Q(t)$$

The maximum condition is now

$$\frac{\partial \widetilde{\mathcal{H}}}{\partial Q(t)} = MR - \ MC - \lambda(t) = 0$$

$$MR - MC = \lambda(t)$$

The adjoint equation is the same as before, but the transversality condition is now

$$\widetilde{\mathcal{H}}(T) = P\big(Q(T)\big)Q(T) - C\big(Q(T)\big) - \lambda(T)Q(T) = 0$$

$$P\big(Q(T)\big)Q(T) - C(Q(T) - (MR - MC)Q(T) = 0.$$

Therefore, at time T, the firm extracts the quantity that satisfies

$$AR - AC = MR - AC$$

as this quantity maximizes the difference between average cost and average revenue.

Hotelling's 1931 theory is concerned with how the behaviour of these individual firms affects total economic welfare (Hotelling, 1931). It assumes that the extraction of a resource is socially optimal when the sum of consumer and producer surplus is maximized[1]. Consumer surplus is the sum of the difference between consumers' willingness to pay and the price they pay, and conversely, producer surplus is the sum of the difference between producers' marginal cost, and the price they receive. In Nova Scotia, there is both a wholesale market and a retail market. In the wholesale market, the offshore firms are the producers, and the distributor is the consumer, so that consumer surplus is the difference between the distributor's marginal revenue, and the wholesale price. In the retail market, the distributor acts as producer, and the residential, commercial and industrial customers are the consumers, and, as before, their surplus is measured as the difference between their willingness to pay and the retail price.

In the context of Hotelling's model, the stream of net benefits at any time is measured as total welfare rather than profit. Due to insufficient data, I do not know the exact from of the producer cost function, but for the purpose of tractability, I assume constant marginal cost with respect to quantity extracted. Therefore, c represents a constant marginal cost (i.e. the cost of extracting an additional unit of stock). The current value Hamiltonian is therefore

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[1] This analysis ignores any potential externalities associated with the extraction and use of a non-renewable resource such as natural gas.

$$\widetilde{\mathcal{H}}\big(t,P(t),Q(t),\lambda(t)\big)=\frac{\big(\bar{P}-P(t)\big)Q(t)}{2}+(P(t)-c)Q(t)-\lambda(t)\big(Q(t)\big) \tag{18}$$

where $P(t)$ is measured by the inverse demand function,

$$P(t)=\ \bar{P}-aQ(t) \tag{19}$$

and $-a$ is the slope of the inverse demand curve. $Q(t)$ denotes the market quantity, and $\bar{P}$ is the choke price, the highest price consumers are willing to pay before quantity demanded falls to zero. The maximum condition is therefore given as

$$\frac{\partial\widetilde{\mathcal{H}}}{\partial Q(t)}=\ \bar{P}-aQ(t)-MC-\ \lambda(t)=\ 0$$

$$P(t)-\ MC=\ \lambda(t)$$

which is identical to (11). The adjoint equation yields the same result as (12)

$$\dot{\lambda}-\ \delta\lambda=-\frac{\partial\widetilde{\mathcal{H}}}{\partial x(t)}$$

$$\frac{\dot{\lambda}}{\lambda}=\delta$$

Note that if one were to assume that extraction costs are 0, then from the adjoint equation and the maximum condition, Hotelling's rule is shown, which states that the price rises at the discount rate (Hotelling, 1931). The transversality condition is

$$\widetilde{\mathcal{H}}(T)=\frac{(\bar{P}-(\bar{P}-aQ(T)))Q(T)}{2}+(\bar{P}-aQ(T)-\ c)Q(T)-\ \lambda(T)Q(T)=\ 0. \tag{20}$$

It can be shown that (20) is satisfied when the end quantity extracted is 0, which of course occurs at $\bar{P}$. Given that the price path and shadow price path of competitive firms are identical to the social optimum, it is clear that in a perfectly competitive market where firms have perfect foresight, the market achieves the social optimum.

This is not the case in a monopoly market. Firms extract up to the point where their marginal revenue, rather than their price, is equal to the sum of their marginal cost and opportunity cost ($\lambda(t)$). The monopolist's benefit from the resource is, as before, maximized profit, but unlike a price taking firm, the market power of the monopolist allows them to mark up their price as high as given demand will allow. A monopoly's price is therefore determined by the inverse demand itself. The monopoly's current value Hamiltonian is therefore given as

$$\tilde{\mathcal{H}} = (\bar{P}Q(t) - aQ(t)^2 - C\big(Q(t)\big) - \lambda Q(t) \quad (21)$$

The maximum condition is given by

$$\frac{\partial \tilde{\mathcal{H}}}{\partial Q(t)} = \bar{P} - 2aQ(t) - c - \lambda = 0 \quad (22)$$

$$MR - MC = \lambda$$

The adjoint equation is the same before, given by equation (12). Meanwhile, the transversality condition is the following

$$\tilde{\mathcal{H}}(T) = \bar{P}Q(T) - aQ(T)^2 - C\big(Q(T)\big) - \lambda Q(T) = 0 \quad (23)$$

This is satisfied when

$$AR - AC = MR - MC \quad (24)$$

at time *T*, where the producer extracts the quantity that maximizes the difference between the demand curve (i.e., average revenue), and the average cost.

Because the monopoly holds back the quantity extracted each period in order to charge a higher price, the lifetime of the resource is extended. However, it results in a loss of consumer surplus of $\frac{\left(P^M(t) - P^*(t)\right)\left(Q^*(t) - Q^M(t)\right)}{2}$, where the superscript M, indicates the monopolist's optimal price and quantity, and * denotes the socially optimal, perfectly competitive market price and quantity.

The above model shows the behaviour of an extractive firm under two market conditions. It is therefore representative of the offshore producers, who sell to the distributor Heritage Gas. If the producing firms were competitive then they would charge Heritage Gas $P^*(t) = MC + \lambda(t)$ per unit of natural gas. However, if they enjoy a degree of market power, then they are able to mark up the price to Heritage Gas.

4.3 Distributor's Marginal Revenue

In the following section, I use the general theory previously discussed to examine the specific case of Heritage Gas as the Nova Scotia distributor. As the distributor, Heritage Gas purchases the natural gas from the offshore producers, and delivers it through pipeline systems to provincial customers. As before, insufficient data prevents an accurate estimation of the distributor cost function. However, as in the case of the producers' cost function, for reasons of tractability, a constant marginal cost with respect to quantity can be assumed, such that

$$\frac{\partial C_{HG}\big(Q(t)\big)}{\partial Q(t)} = c_{HG}$$

$$c_{HG} = P_{OS}(t) + c_{HG_+}$$

where c_{HG_+} represents the additional marginal cost per unit of gas faced by the distributor, Heritage Gas, other than the wholesale price of the gas. As before, $P_{OS}(t)$ represents

the wholesale price. Following Guldmann (1983) and Bernard, Bolduc, and Hardy (1998), I could assume that the marginal cost per cubic meter to Heritage Gas should not be larger than the wholesale price of natural gas. Under that assumption, $c_{HG_+} = 0$. Unlike these previous studies, I allow for $c_{HG_+} > 0$ in my analysis. Recall equation (4), which shows

$$MR - MC = 0.$$

From this, we know that

$$\bar{P} - 2aQ(t) - c_{HG} = 0$$

$$\big(P_{HG}(t) + aQ(t)\big) - 2aQ(t) - (P_{OS}(t) + c_{HG+}) = 0$$

$$P_{HG}(t) - aQ(t) - P_{OS}(t) - c_{HG+} = 0$$

From the equation above, the profit-maximizing retail price is estimated as

$$P_{HG}(t) = aQ_d(t) + P_{OS}(t) + c_{HG_+} \tag{25}$$

which is clearly higher than the marginal cost if $a > 0$ (i.e., Heritage Gas has market power). For example, assuming the linear inverse demand curve $P = \bar{P} - aQ$, to equate marginal revenue, $\bar{P} - 2aQ$, with marginal cost, is to equate the price, P, with $aQ + MC$.

If the distributor behaves competitively then, from equation (2), the profit-maximizing price is given by

$$P_{HG}(t) = P_{OS}(t) + c_{HG+}$$

It is clear from the above that if the Utility Review Board allows the distributor any degree of market power, then their price varies with quantity.

4.4 Producer's Marginal Revenue (Offshore Firms)

If the producer exists in a competitive market, then its marginal revenue is simply the given price, which is set at its marginal cost, and equations (10) and (11) describe its pricing. Meanwhile, an offshore producer with monopoly power faces the profit maximization problem described by equations (21) and onward. Assuming inverse linear market demand of the following form,

$$P_{OS}(t) = \bar{P}(t) - aQ_d(t),$$

the producer's marginal revenue curve depends on the level of market power held by the distributor. If the distributor is competitive, then its demand for gas is the province's aggregate demand for gas, shown in the above, and therefore, the producer also responds to the above demand function. Under this condition, the producer's Total Revenue (TR_{OS}) is given by $\left(\bar{P}(t) - a_{OS}Q_d(t)\right)Q_d(t)$. The producer's marginal revenue is therefore given by $\frac{\partial TR_{OS}}{\partial Q_d(t)}$.

In a market structure where the distributor is also a monopoly, it too equates marginal revenue and marginal cost. Total Revenue is given by $\left(\bar{P}(t) - aQ_d(t)\right)Q_d(t)$. Since the distributor's marginal revenue curve represents its demand from the offshore, in this scenario, the producer responds to the distributor's marginal revenue. Therefore, the producer's Total Revenue is $\left(\frac{\partial TR_{HG}}{\partial Q_d(t)}\right)Q_d(t)$, and marginal revenue is still given by $\frac{\partial TR_{OS}}{\partial Q_d(t)}$.

4.5 Combinations of Market Structures: Examples

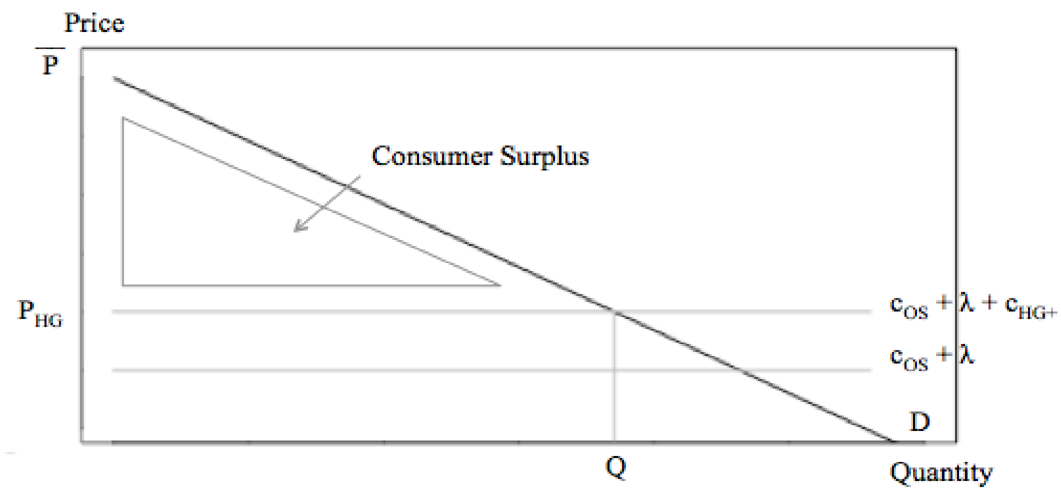
The following three sections outline different combinations of the market regimes outlined in the theory section, for the producer and distributor, and how these affect the price and quantity demanded, and therefore, consumer welfare.

4.5.A Competitive Producer, Competitive Distributor

A competitive producer offshore faces a demand for natural gas from a distributor. It accepts the market price as given. Because it has no market power in a competitive scenario, the offshore firm cannot raise its price above $P^*(t)_{OS} = c_{OS} + \lambda(t)$, where c_{OS} is the producer's marginal cost of extracting a unit of gas, and $\lambda(t)$ represents the opportunity cost of extracting that unit. Meanwhile, the distributor's demand for natural gas is equivalent to the provincial aggregate demand for natural gas if it is competitive.

The retail price that provincial customers will pay is given by $P^*(t)_{HG} = P^*(t)_{OS} + c_{HG+}$. Consequently, consumers demand $Q_d^*(t) = \frac{\bar{P}(t)}{a} - \frac{1}{a}P^*(t)_{HG}$. Figure 11 demonstrates this market structure, wherein Line D is the demand curve, and consumer surplus is shown as the area $\frac{\left(\bar{P}(t) - P_{HG}^*(t)\right)Q^*}{2}$.

Figure 4. Competitive Producer and Competitive Distributor



4.5.B Offshore Monopoly, Competitive Distributor

Figure 5. Monopoly Producer and Competitive Distributor

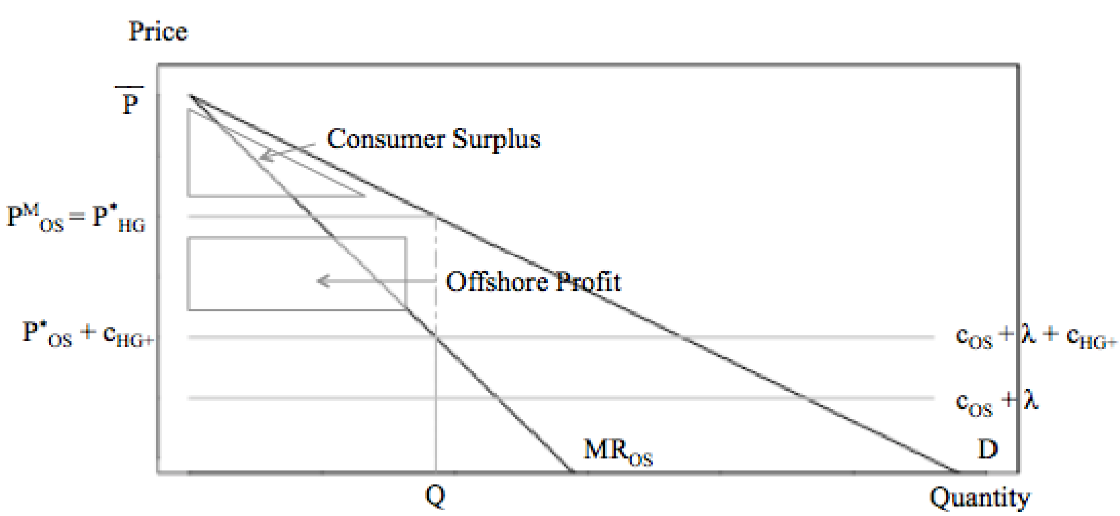


Figure 5 depicts a scenario where the producer enjoys a monopoly offshore, but the distribution market is competitive. The producer still faces the same marginal and opportunity cost, however, with monopoly power, the firm produces the quantity that equates the firm's marginal revenue with its marginal cost, and prices the gas according to the distributor's demand (which is, again, equivalent to provincial demand), such that the profit maximizing wholesale price is $P(t)_{OS} = aQ_d(t) + c_{OS} + \lambda(t)$. The distributor purchases the gas at this price. The distributor sells the gas at a price of $P^*(t)_{HG} = P(t)_{OS} + c_{HG+}$, and aggregate quantity demanded is $Q_d(t) = \frac{\bar{P}(t)}{a} - \frac{1}{a}P^*(t)_{HG}$.

4.5.C Offshore Monopoly, Distributor Monopoly

Figure 6. Monopoly Offshore and Monopoly Distributor

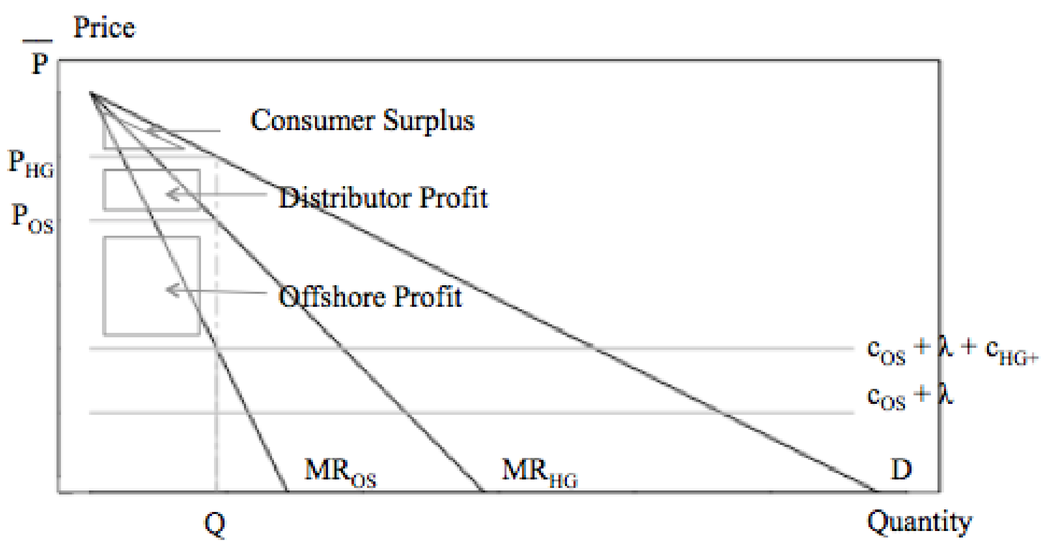


Figure 6 illustrates a scenario where both the producer and distributor enjoy some degree of market power. The producer will extract the quantity that equates $c_{OS} + \lambda(t)$ with its own marginal revenue function, and mark up its wholesale price accordingly. From equation (4),

$$\bar{P}(t) - 4aQ_d(t) = c_{OS} + \lambda(t)$$

$$P_{OS}(t) + 2aQ_d(t) - 4aQ_d(t) = c_{OS} + \lambda(t).$$

The distributor buys the gas at the price

$$P_{OS}(t) = 2aQ_d(t) + c_{OS} + \lambda(t),$$

and distributes it at the price

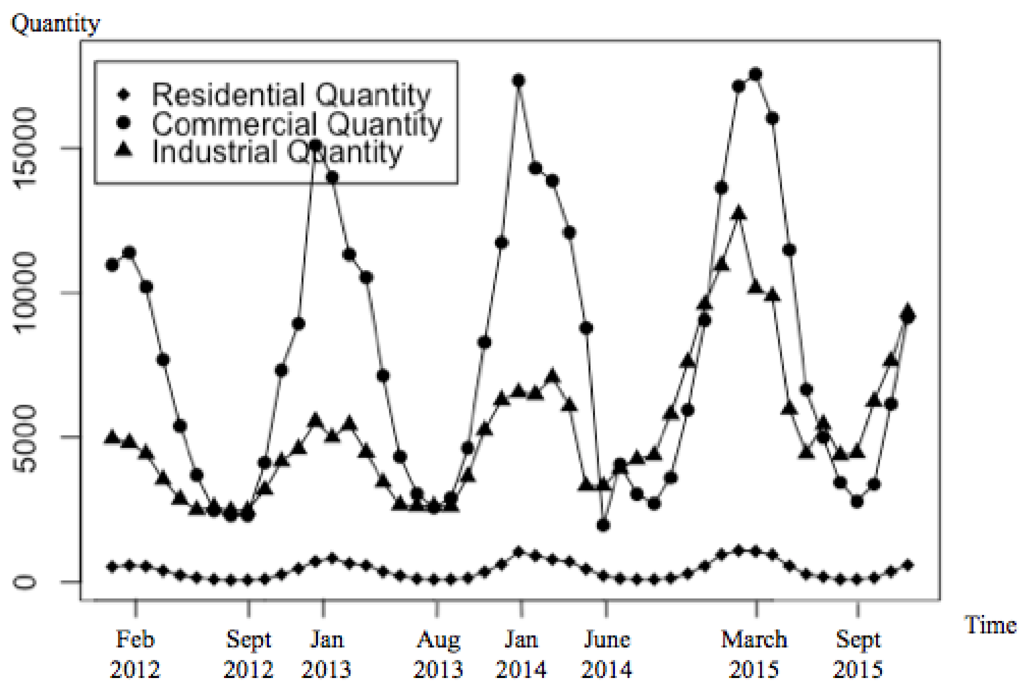
$$P(t)_{HG} = aQ_d(t) + P(t)_{OS} + c_{HG+}$$

Figure 6 demonstrates that these price mark-ups, and lower production result in higher profits for both the firms, but at the expense of a significant reduction in consumers' welfare.

Chapter 5. Data

My analysis uses data from various sources. Statistics Canada's Natural Gas Transmission Survey (Table: 25-10-0033-01) provides data on the quantity of natural gas sold by utilities to residential, commercial, and industrial customers each month for the years 2012-2015 (previous years are unavailable through Statistics Canada), measured in thousands of cubic meters. For this reason, I only use data for those years to obtain the necessary estimates of parameters, which are assumed to be representative of the lifetime of the offshore project.

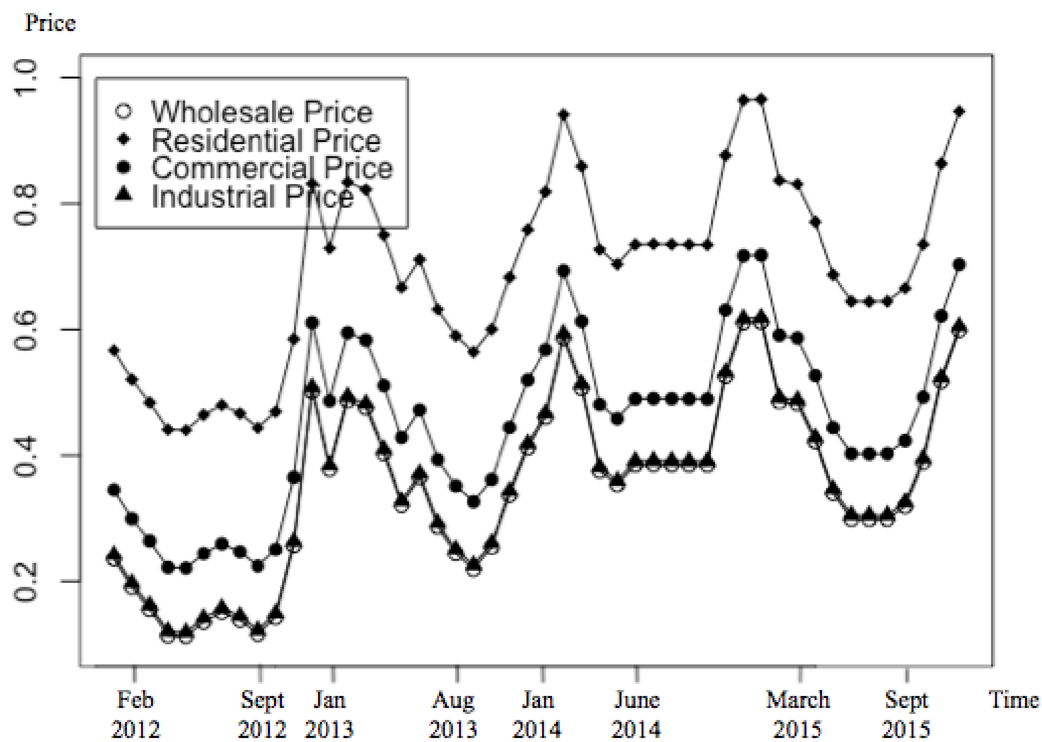
Figure 7. Residential, Commercial, and Industrial Sales



The sales data demonstrate a cyclical pattern of demand, shown in Figure 7. The peaks and troughs shown in the data represent the fluctuations in demand caused by the changes in the seasons. In the warmer summer months, the need for natural gas for heating declines, and as temperatures decrease in the fall and winter, demand increases once again.

Wholesale and retail price data are provided by Heritage Gas' accounting department. These data include the wholesale price of gas that Heritage Gas pays to the offshore producers per unit of gas[2]. As well, additional unit charges are administered to the consumers, which vary by customer class (residential, commercial, industrial)[3]. The wholesale and the retail prices all demonstrate a cyclical pattern similar to that of the sales data, as shown in Figure 8, which again reflects the seasonal demand patterns. The price data are also adjusted for inflation before the analysis using Statistics Canada's Nova Scotia Consumer Price Index (Table 18-10-0004-01), which is rescaled so that all price data are in constant 2018 dollars.

Figure 8. Wholesale, Residential, Commercial, and Industrial Price



Exchange rate data (EXCAUS) are provided by the Board of Governors of the Federal Reserve System (US) and represents the value of one US dollar in Canadian dollars. The offshore firms' discount rate is represented by a constant American discount

[2] Heritage Gas buys the gas at this rate, to distribute it to its own customers, of which there are three classes. In this distribution market, Heritage Gas charges its customers a unit price equal to the wholesale price to recover the cost

[3] The data are measured in dollars per gigajoule of natural gas, but are converted into dollars per m^3 before the analysis is performed.

rate, based on the American Prime Rate between 2012 and 2015. Summary Statistics for data described are provided in Table 1.

Table 1. Summary Statistics

Variable	Minimum	Median	Maximum	Mean
Residential Quantity (1000m^3)	70	360	1091	419.5
Commercial Quantity (1000m^3)	1969	7234	1756.2	7954
Industrial Quantity (1000m^3)	2476	4545	1271.3	5460
Total Quantity (1000m^3)	4852	1216.7	3095.4	1363.3
Wholesale Price (2018\$/m^3)	0.1125	0.37	0.6117	0.3507
Residential Price (2018\$/m^3)	0.44	0.7191	0.9661	0.6946
Commercial Price (2018\$/m^3)	0.2207	0.4765	0.7180	0.4572
Industrial Price (2018\$/m^3)	0.1191	0.3764	0.6182	0.3571
CAD/USD Exchange Rate	0.9783	1.0689	1.3713	1.1032
Discount Rate	0.03292	0.03292	0.03292	0.03292

Chapter 6. Empirical Methodology

6.1 Evidence of Distributor Market Power

First, I look for evidence that suggests that the offshore firms and Heritage Gas have any market power. Recall equation (25), which shows that the profit maximizing retail price is given by $P(t)_{HG} = aQ_d(t) + P(t)_{OS} + c_{HG_+}$. It is possible to estimate the distributor's degree of market power in each market (i.e., residential, commercial, and industrial) by regressing

$$P(t)_{HG\,i} = \alpha + \beta P(t)_{OS} + \gamma Q_{d\,i} \tag{27}$$

where i indexes market type, $P_{OS}(t)$ is the offshore price of the gas, while $Q_d(t)$ is the quantity of gas demanded by market type i from Heritage Gas. β is expected to be roughly equal to 1, and if $\gamma > 0$ then the distributor is exercising market power. Additionally, $\alpha > 0$ could mean one of two things: i) either $c_{HG_+} > 0$, meaning the firm does indeed have additional marginal costs per m^3 of gas; or, ii) or α is an additional price mark up by the distributor, meaning they incur their marginal cost of $P(t)_{OS}$ and then charge $P(t)_{OS} + \alpha$ for each m^3 of gas.

Using the results of the above regression, the inverse demand function for each of the three markets (residential, commercial, industrial) is obtained. Because γ represents the variation in Heritage Gas' price with respect to quantity, $-\gamma$ represents the slope of the inverse demand curve. The estimated inverse demand functions are therefore

$$P(t)_{HG} = \bar{P}(t)_{HG} - \hat{\gamma}Q_d(t)$$

In order to estimate the inverse demand functions, the choke price (i.e. the maximum price that can be charged before demand falls to zero) must also be estimated. These are obtained from

$$\bar{P}(t)_{HG} = P(t)_{HG} + \hat{\gamma}Q_d(t)$$

which is obtained from rearranging the above inverse demand function.

6.2 Estimating Heritage Gas' Aggregate Demand

For the period of study, no underground gas storage existed in Nova Scotia, and it is therefore a safe assumption that the natural gas sold at time t represents quantity demanded at time t. Heritage Gas' demand for natural gas follows a predictable, seasonal pattern. In winter months, heating demand increases. Hypothetically, this would result in the demand curve for natural gas shifting rightward, as consumers not only demand higher volumes of gas, but also exhibit a higher willingness to pay. As temperature rises in the spring and summer months, demand gradually shifts down again. This makes modelling the demand curve challenging, as the intercept parameters of the demand function change depending on t. Figure 7 demonstrates the seasonal pattern of quantity demanded in the residential, commercial, and industrial market respectively.

To account for these seasonal fluctuations, Heritage Gas' inverse demand for natural gas from the offshore is modelled as

$$P(t)_{HG} = \bar{P}(t) - a_{HG}Q_d(t) \tag{28}$$

The intercept $\bar{P}(t)$ is its own function that accommodates the effect of the seasonal cycle on the quantity demanded. The intercept is therefore of the form

$$\bar{P}(t)_{HG} = \alpha + \beta t + \gamma \sin\left[\left(\frac{t}{12}\right)2\pi\right] \tag{29}$$

Using the inverse demand function

$$P(t) = \bar{P}(t) - aQ_d, \tag{30}$$

the marginal revenue is given by $MR = \bar{P}(t) - 2aQ_d(t)$. The distributor's optimum is given by,

$$MR = c_{HG_+} + P_{OS}(t)$$

From the above, I obtain the following

$$P(t) = aQ_d + \left(MC_{OS} + \lambda(t)\right) \tag{31}$$

$$P(t) = c_{OS} + aQ_d + \lambda(0)Ee^{\frac{rt}{12}} \tag{32}$$

where r is a constant US real interest rate, 0.03292, and is based on the US prime rate from 2012-2015. E is the CAD/USD exchange rate from 2012-2015. To obtain estimates of the offshore firms' marginal cost, the slope of Heritage Gas' inverse demand function, and the initial shadow price, the wholesale price of gas is regressed on quantity demanded and $Ee^{\frac{rt}{12}}$, as per (32); the expected results are $\hat{c}_{OS} \geq 0, \hat{a} \geq 0, \hat{\lambda}(0) \geq 0$.

Estimates of the choke price are obtained from the fact that at any given time, $\bar{P}(t) = P(t) + aQ_d$. Because Heritage Gas' demand function is essentially its marginal revenue function, the above estimates also allow for the estimation of the aggregate market demand function for natural gas. The above estimates yield

$$MR_{HG} = \bar{P}(t) - \hat{a}Q_d$$

which is equivalent to equation (19). Therefore, inverse aggregate market demand is given by

$$P(t) = \bar{P}(t) - \frac{\hat{a}}{2}Q_d \tag{33}$$

This is obtained from the fact that the distributor's marginal revenue curve is the first derivative of the firm's Total Revenue, and therefore has twice the slope of the aggregate demand curve. This is shown in Chapter 4.5.

Chapter 7. Results

7.1 Evidence of Distributor Market Power: Regression Analysis

An ordinary least squares regression is performed for equation (27) (which relates the distributor's price to the offshore price, quantity demanded, and the intercept parameter) using data for each separate market: residential, commercial, and industrial. The results are presented in Table 2. An additional regression of equation (29) is performed to estimate the pattern of the choke price over time. These results are presented in Table 3.

Table 2. Distributor Market Power Regression Results

Variable	**Residential Price (2018$/m^3)**	**Commercial Price (2018$/m^3)**	**Industrial Price (2018$/m^3)**
Wholesale Price (2018$/m^3)	1.055*** (7.604e-03)	9.918e-01*** (1.779e-03)	9.998e-01*** (1.486e-04)
Quantity (m^3)	-3.066e06 (3.45e-06)	1.46e-07** (5.301e-08)	-8.133e-09 (8.578e-09)
Intercept	3.261e-01*** (2.326e-03)	1.082e-01*** (5.868e-04)	6.586e-03*** (3.803e-05)
n	48	48	48
R^2	0.9984	0.9999	1

Significance: ** 5%, *** 1%

From Table 2, unusually high R^2 values are observed for each regression. In each regression, over 99 percent of the variation in the retail price of gas is explained by the variations in the wholesale price, and the quantity demanded.

For the residential market, the model yields highly significant estimates for the intercept term and the coefficient on the wholesale price. The coefficient on the wholesale price is 1.055, showing the expected one-to-one relationship between the wholesale and retail price. This means that when the offshore producers increase the wholesale price by one unit, the residential retail price increases by an equal amount. The intercept term is 0.3261, meaning that the retail price is $0.3261 2018$/m^3 above the wholesale price of gas. Therefore, either Heritage Gas does indeed have additional marginal costs per cubic meter, or they mark their retail price up above the wholesale price by thirty-three cents per cubic meter. The coefficient on quantity demanded is not significantly different from zero. From these results, the choke price can be estimated as

$$\bar{P}_{res}(t) = P_{res}(t) + 3.066 \times 10^{-6} Q_{d_{res}}(t)$$

The results of these estimates for each month of the study period are provided in the Appendix. Using the results presented in Tables 2 and 3, inverse demand in the residential market is estimated as

$$P_{res}(t) = \left(0.51 + 0.0075t + 0.086\sin\left[\left(\frac{t}{12}\right)2\pi\right]\right) - 3.066 \times 10^{-6} Q_{d_{res}}(t)$$

Table 3. Choke Price Regression Results

Variable	Residential Market	Commercial Market	Industrial Market
Time	0.007520*** (0.001082)	0.006883*** (0.001049)	0.006986*** (0.001044)
Sine Curve	0.085837*** (0.021197)	0.082154*** (0.020549)	0.081337*** (0.020454)
Intercept	0.511675*** (0.030318)	0.289756*** (0.029391)	0.186041*** (0.029255)
n	48	48	48
R^2	0.5347	0.5099	0.5172

Significance: ** 5%, *** 1%

When the model is applied to data in the commercial market, all results are highly significant. Again, the one-to-one relationship between the wholesale and retail price is shown, as the coefficient on the offshore price is 0.9918. The significance of the coefficient on quantity demanded, 1.46×10^{-7}, indicates that Heritage Gas does indeed enjoy market power in the commercial market. An additional cubic meter of demand in the commercial market is associated with a significant 1.46×10^{-7} 2018\$/m^3 increase in the commercial price. The significance of the intercept term suggests a further increase in the commercial price, unrelated to quantity. Again, this indicates either an additional price mark up or an additional marginal cost, $c_{HG_{+comm}}$ = 0.1082 2018\$/m^3. The choke price for the commercial market is

$$\bar{P}_{comm}(t) = P_{comm}(t) + 1.46 \times 10^{-7} Q_d(t)_{comm}$$

and the results are also provided in the Appendix. Inverse commercial demand is therefore estimated as

$$P_{comm}(t) = \left(0.29 + 0.0069t + 0.82\sin\left[\left(\frac{t}{12}\right)2\pi\right]\right) + 0.0821.46 \times 10^{-7} Q_{d_{comm}}(t)$$

Finally, the industrial market has an insignificant coefficient on quantity demanded, but significant results elsewhere. Like in the previous markets, the coefficient on the wholesale price is roughly equal to one, at 0.9998, as a unit increase in the wholesale price creates a unit increase in the retail industrial price. The intercept term is significant at 0.006586, which means either $c_{HG+_{ind}} = 0.006586$ 2018$/m^3, or the industrial price is marked up by $0.006586 2018$/m^3. From the regression results, the choke price is

$$\bar{P}_{ind}(t) = P_{ind}(t) + 8.133 \times 10^{-9} Q_{d_{ind}}(t)$$

These results are also given in the Appendix. Again, using the results shown in Tables 2 and 3, inverse industrial demand is estimated as

$$P_{ind}(t) = \left(0.19 + 0.007t + 0.081\sin\left[\left(\frac{t}{12}\right)2\pi\right]\right) - 8.133 \times 10^{-9} Q_{d_{ind}}(t)$$

It should also be noted that the intercept estimates differ by customer class. It is highest for residential customers at 0.3261, and decreases for commercial customers at 0.1082, while industrial customers have the lowest intercept at 0.006586. As stated earlier, I allow for the possibility that $c_{HG+i} \geq 0$, but as previous studies have found these additional distribution costs to be insignificant for all classes, or are at least insignificant for non-residential customers. One could also interpret the decreasing intercept values as a decrease by degree of bargaining power of each customer class. Residential customers, who demand a relatively small amount of the commodity, would have little to no bargaining power relative to large commercial or industrial buyers.

7.2 Estimating Heritage Gas' Aggregate Demand: Regression Analysis

The results of the regression of equation (32) (which relates the inverse demand to producer's marginal cost, quantity demanded, and the shadow price) are shown in Table 4. The dependent variable is the wholesale price of gas per cubic meter. As expected, the marginal cost to the offshore producers of extracting an additional unit of gas is negligible, and can be estimated at zero. The slope of the Heritage Gas' inverse demand curve is significant at 1.07×10^{-5}, so a marginal increase in the quantity demanded by

Heritage Gas decreases the price by 1.075×10^{-5} 2018\$/m^3. Finally, the initial shadow price at $t = 0$ is significant and equal to 0.3143 2018\$/m^3. Its value in US dollars grows each period by the factor $e^{\frac{r}{12}}$.

Equation (11) shows that in the socially optimal, competitive scenario, the offshore firms' optimal price is given by

$$P^*_{OS}(t) = c_{OS} + \lambda(t)$$

Recall that

$$P^*_{HG}(t) = P^*_{OS}(t) + c_{HG+} = MC_{OS} + \lambda(t) + c_{HG+},$$

where $c_{HG+} \geq 0$. Given the above regression results, it is clear that

$$P^*_{OS}(t) = \lambda(t) = \$0.3143e^{\frac{rt}{12}}/m^3 \tag{34}$$

From the previous results, inverse aggregate market demand is given by

$$P(t) = \bar{P}(t) - 1.075 \times 10^{-5} Q_d(t)$$

This means that a one unit change in the aggregate quantity demanded fro natural gas in Nova Scotia results in a significant price change of $\$1.075 \times 10^{-5}$. Alternatively, aggregate market demand curve is estimated at

$$Q_d(t) = \bar{P}(t) - 93023.256P(t)$$

which means that a one unit price increase results in a 93 023m^3 change in quantity demanded.

Table 4. Offshore Market Regression Results

Variable	Estimate
Total Quantity (m^3)	1.075e-05*** (2.162e-06)
Discount Factor (USD)	3.143e-01** (9.058e-02)
Intercept	-1.684e-01 (1.039e-01)
n	48
R^2	0.5294

Significance: ** 5%, *** 1%

Chapter 8. Conclusion

The presence of natural gas reserves represents a large stock of resource wealth in the province. The distribution of the benefits from this resource is a question of concern. The goal of this study is to determine whether the market structure of the Nova Scotia natural gas industry has resulted in a non-socially optimal distribution of economic welfare, by testing whether the producers or distributor engage in price mark-ups.

From the previous sections' results, the optimal wholesale price at t, which would maximize consumer surplus, is the present value shadow price ($\$0.3143e^{\frac{rt}{12}}/\mathrm{m}^3$), regardless of the seasonal fluctuations in demand. However, the wholesale price follows the seasonal pattern consistently (shown in Figure 5). This suggests that the offshore firms are manipulating their price based on the quantity demanded. Though this does not provide definitive evidence of monopoly power for the offshore firms, it is suggestive of it. This seasonal price pattern may also serve as a mechanism for regulating demand. To prevent supply shortages during peak demand season, the producers may raise prices to offset some of the increased demand. The Nova Scotia Utility and Review Board does not regulate this wholesale price.

The results for the residential market show insignificant quantity-based price mark ups, so there is no definite evidence of distributor market power in the residential market. However, the results do show that the distributor may be faced with additional marginal distribution costs ($0.3261 2018$/m^3). Based on the results of previous studies, this value may instead represent a non-quantity based price mark up for residential customers.

In the commercial market, there is evidence of quantity-based price manipulation. Based on the study, the distributor increases the commercial price (by $\$1.46\times 10^{-7}/\mathrm{m}^3$) given a unit increase in quantity demanded. It should be noted that though this result is significant, it is quite small. Furthermore, the distributor either engages in an additional price mark-up, or they face an additional marginal distribution cost (0.1082 2018$/$\mathrm{m}^3$).

Finally, results in the industrial market show no definite evidence of quantity-based price manipulation. As is the case in the residential market, the result is insignificant from zero. However, the distributor may mark up the price independently of quantity demanded (by 0.006586 2018$/$m^3$), but as before, this value could instead represent additional marginal costs for the distributor.

Though it cannot be said with certainty that the additional marginal distribution cost (c_{HG_+}) is negligible, evidence from previous studies suggests that this is a definite possibility, as other costs faced by the distributing firm represent fixed capital costs. It is also worth noting that the additional charge to customers per unit of gas, which Heritage Gas refers to as the Base Energy Charge (BEC), is highest for residential customers, who would have little to no bargaining power with the distributor, and is lowest for industrial customers, who, arguably, would have the most bargaining power.

Figures 4, 5 and 6 demonstrate consumer surplus under both market regimes. In the socially optimal competitive scenario shown in Figure 4, total welfare is given by consumer surplus as the area beneath the demand curve and above the marginal cost/supply curve. In the scenario where both firms have market power, welfare is given by the sum of consumer surplus, distributor's producer surplus, and offshore producer surplus as the areas indicated in Figure 6. Using welfare as a measurement, it is clear that under the competitive regime, provincial consumers are better off. The reserves of natural gas in Nova Scotia are on Crown land, and the right to explore and extract from these reserves are awarded through a call for bids process authorized by the Canada-Nova Scotia Offshore Petroleum Board. The Nova Scotia Utility Review Board awards the franchise rights for the distribution of natural gas, and regulates retail prices. The structure of this market precludes strong competition, which drives efficiency, lower prices, and therefore greater welfare for provincial consumers in Nova Scotia. As government bodies, the purpose of the Boards is, in part, to ensure that the corporations participating in the industry operate in such a way that maximizes the benefits of the projects to the province. This involves regulating prices to prevent firms from practicing market power. To this end, the Nova Scotia Utility and Review Board has been relatively effective. However, market power is indeed practiced in the commercial market to a small degree, and if the distributor does not face additional marginal costs, then it is also practiced in the other markets as well.

The loss of welfare caused by a non-competitive market regime means that a large wealth transfer from the consumers to both corporations whose ownership is outside the province, has taken place. Though the structure of the market in Nova Scotia may help facilitate the establishment of an industry that entails significant barriers to entry, using economic welfare as a measurement, a non-competitive structure may allow the practice of monopolistic pricing. Some evidence of this is demonstrated in the commercial retail market, and some additional evidence suggests the practice by the producers and the distributor.

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Appendix: Choke Price Estimates

Date	Residential Choke Price	Commercial Choke Price	Industrial Choke Price
Jan 2012	0.5686566	0.3466871	0.2423060
Feb 2012	0.5221125	0.3009766	0.1969608
March 2012	0.4856945	0.2654098	0.1619862
April 2012	0.4421775	0.2228852	0.1202439
May 2012	0.4407572	0.2214586	0.1190757
June 2012	0.4647200	0.2443857	0.1417556
July 2012	0.4803071	0.2598185	0.1572984
Aug 2012	0.4668319	0.2470070	0.1447922
Sept 2012	0.4437549	0.2242197	0.1221463
Oct 2012	0.4699018	0.2509882	0.1488636
Nov 2012	0.5856610	0.3661194	0.2632560
Dec 2012	0.8329621	0.6118124	0.5081520
Jan 2013	0.7312407	0.4889042	0.3843518
Feb 2013	0.8366309	0.5967667	0.4936328
March 2013	0.8242002	0.5848372	0.4822353
April 2013	0.7520991	0.5123353	0.4096331
May 2013	0.6681726	0.4292270	0.3272883
June 2013	0.7118563	0.4729302	0.3713949
July 2013	0.6323304	0.3938737	0.2926634
Aug 2013	0.5902534	0.3518107	0.2506692
Sept 2013	0.5647726	0.3265211	0.2254011
Oct 2013	0.6006972	0.3622379	0.2607363
Nov 2013	0.6842205	0.4454735	0.3433815
Dec 2013	0.7607845	0.5212496	0.4184560
Jan 2014	0.8218291	0.5705007	0.4671665
Feb 2014	0.9447215	0.6953916	0.5933188
March 2014	0.8622619	0.6147696	0.5133712
April 2014	0.7292982	0.4824290	0.3815505
May 2014	0.7049358	0.4595402	0.3595850
June 2014	0.7355942	0.4900687	0.3911751
July 2014	0.7362793	0.4910299	0.3917030
Aug 2014	0.7357018	0.4905531	0.3914439
Sept 2014	0.7351987	0.4901780	0.3911837
Oct 2014	0.7348494	0.4899819	0.3909343
Nov 2014	0.8777497	0.6317607	0.5319904
Dec 2014	0.9665139	0.7183497	0.6174074
Jan 2015	0.9690257	0.7199876	0.6182526
Feb 2015	0.8403246	0.5933654	0.4919351
March 2015	0.8341193	0.5891012	0.4883147
April 2015	0.7740408	0.5289938	0.4283616
May 2015	0.6888204	0.4455959	0.3461185

Date	Residential Choke Price	Commercial Choke Price	Industrial Choke Price
June 2015	0.6458398	0.4035876	0.3051248
July 2015	0.6451322	0.4030788	0.3049317
Aug 2015	0.6452940	0.4031183	0.3051243
Sept 2015	0.6660956	0.4235000	0.3254742
Oct 2015	0.7355769	0.4930728	0.3950383
Nov 2015	0.8651891	0.6222551	0.5237625
Dec 2015	0.9488412	0.7045326	0.6051627