THE MARGINAL COST OF NATURAL GAS DISTRIBUTION PIPELINES: 
THE CASE OF SOCIÉTÉ EN COMMANDITE GAZ MÉTROPOLITAIN, QUÉBEC

by

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JEL classification L95
**SUMMARY**

Investment expenditures in natural gas distribution pipelines account for 70% of the rate base of Société en Commandite Gaz Métropolitain (SCGM), the natural gas utility which serves most customers in the province of Québec. In allocating these costs to rate payers, the regulatory process divides costs into an access fee which reflects the fixed costs of planning and implementing the system that is to be divided equally over all users and a user or variable cost fee reflecting the capacity they use. In this paper we estimated a cost function to provide information to regulators on how these tariffs should be set. We use a unique data set of 131 observations which represent natural gas extension projects realized by SCGM in four Québec regions (Trois-Rivières, Sherbrooke, Québec and Chicoutimi) in the eighties and early nineties, to analyze the main determinants of capital costs. It is found that capital cost is not separable into a fixed and a variable component, that the elasticity with respect to maximum daily demand is not significant, and that the elasticity with respect to pipe length is slightly less than one. Maximum daily demand by each consumer class and consumer density per kilometer play no statistically significant role.
**Introduction**

Since 1985, the producer price of natural gas has been deregulated in Canada and every consumer can purchase gas either directly from a producer or through the services of a broker. However, natural gas transportation, storage and distribution are still subject to regulation by public utilities commissions (PUC) due to natural monopoly characteristics associated with these activities. Natural gas transportation from the Alberta border to the Québec border through Trans-Canada Pipelines (TCPL) is regulated by the National Energy Board, storage by Union Gas in Southern Ontario is regulated by the Ontario Energy Board, and transportation within Quebec by the Trans-Québec et Maritimes Pipelines (TQM) and distribution by Société en Commandite Gaz Métropolitain (SCGM) in the province of Québec are regulated by the local public utilities commission known as the Régie de l’énérige.

From the above and the components of the average consumer price of natural gas (17.31¢ /m $^3$) in the province of Québec for the period October, 1$^{st}$ 1994 to September, 30$^{th}$ 1995 (Alberta border price (33.9%), transportation and storage (28.9%), and distribution (37.2%)), we can see that more than 65% of average consumer price is still subject to regulation by federal and provincial commissions. Distribution alone, the focus in this paper, accounts for more than 1/3 of the cost of natural gas to Quebec gas customers. To provide information to regulators on how to apportion the capital part of these distribution costs into a fixed and a variable component, we use a unique data set on 131 natural gas distribution pipeline projects completed by SCGM from 1985 to 1995 that bring natural gas into four Québec regions. We use regression analysis to break distribution capital costs at the project level into a fixed component as represented by the intercept and a variable component as represented by maximum daily demand by consumer class, pipe length, and consumer density by kilometer (km).

The presentation proceeds as follows: the first section gives an overview of the Québec natural gas market and of Société en Commandite Gaz Métropolitain which is the main local distribution company. The second section summarizes previous studies dealing with the marginal cost of natural gas distribution capacity. The third section describes the sample on which this paper is based, and finally, the fourth section presents the econometric model and the empirical
results. The conclusion summarizes the empirical findings and offers some comments on the significance of these findings for the determination of natural gas distribution rates by regulatory commissions.

1- Québec Natural Gas Market and its LDC

Up to the early eighties the distribution of natural gas in the province of Québec was limited to Montréal Island and a few local communities located along the Ontario-Québec border. The 1973 and 1979 oil crises created conditions which were favorable to the substitution away from oil products towards other energy sources and by 1984 natural gas share had increased to 13%. With government incentive programs, the natural gas pipeline distribution network was expanded further into regions of the province of Québec which had had no facilities up to that point in time. The overall length of the natural gas distribution network increased from 2764 km in 1984 to 6853 km in 1993 for an average annual growth rate of 10.1%. Natural gas deliveries followed the increase in capacity and increased from 4277 X 10^6 m^3 in 1984 to 5764 X 10^6 m^3 in 1993 for an annual average growth rate of 3.3%. By 1994 natural gas accounted for 16% of Québec total energy consumption while oil products and electricity contributed respectively 42% and 41%.

During the later part of this expansion since 1985, SCGM has controlled almost all natural gas sales in the province of Québec becoming the fourth largest natural gas distribution company in Canada. To see the importance of distribution costs to SCGM, consider the revenue, cost and asset information in Table 1.

The interest and depreciation expenses of $ 175 million and the net income of $ 135 million are both subject to regulation by Québec PUC. As can be further seen in the Table, a large part of these capital related items is accounted for by distribution assets since the latter alone accounts for 69% of total assets and 89% of net fixed assets.

Québec PUC follows the standard practice of a normal rate of return on the rate base for activities carried on within the province. Required revenues are assessed to cover total costs of
natural gas sales based on a one-year ahead forecast. Once total required revenues are established, they are allocated across tariff classes taking into account sales, peak demand, and other consumer characteristics. Table 2 provides some information on the number of customers, sales, and transportation and average distribution rates in each class for the five main tariff classes. Rates vary as expected with residential customers paying the highest and interruptible customers paying the lowest.

Since natural gas is used mostly for water and space heating, demand follows closely outside temperature over the course of the year. As can be seen from Figure 1, peak consumption occurs during winter months. However, aside from interruptible rates, current tariff schedules show no time variation within a year and do not reflect the marked seasonal patterns. Rather actual tariff schedules have two components: a daily fixed charge per customer and a variable per unit rate which decreases as natural gas consumption increases. The fixed charge covers consumer specific capital such as natural gas line from street to building and meter, and the estimated cost of natural gas access to the users with no delivery. The latter is based on the estimated cost of a fictitious distribution network made of zero diameter pipes and it is allocated uniformly per customer. The remainder of distribution capital cost is allocated across consumer classes on the base of estimated maximum daily demand and it is translated into a downward sloping rate per unit of sale. The market determined natural gas price and the regulated transmission rate from Alberta to the Quebec border are added to this decreasing rate.

It is this breakdown of capital costs between fixed and variable parts that we focus on in the rest of this paper. Indeed, since the costs of gas distribution pipelines represent the bulk of the rate base and hence are a significant component of natural gas rates paid by Quebec customers, we focus our attention solely on the costs of natural gas distribution pipelines.

2- Previous Studies
Although a large empirical literature exists that probes the cost determinants of electricity generation, transmission and distribution, a much smaller effort has been devoted to natural gas distribution. We have found three papers that give us some guidance in dealing with the capital costs of providing natural gas distribution capacity to local communities: (Guldmann (1983), Guldmann (1989) and Guldmann and Hanson (1991)). The basic model which is applied in these three papers is the following:

\[ KD_s = \alpha_o + \sum_i \alpha_{G_i} G_{is} + \sum_i \alpha_{N_i} N_{is} + \alpha_D DEN_s + \epsilon_s \]  

where: 

- \( KD_s \) = distribution capital cost in community \( s \) (real $);
- \( G_{is} \) = annual natural gas sales to tariff class \( i \);
- \( N_{is} \) = number of customers in tariff class \( i \);
- \( DEN_s \) = population density (population per acre);
- \( \epsilon_s \) = error term

This model is suitable for our use, since \( \alpha_o \) represents fixed costs while \( \alpha_{G_i}, \alpha_{N_i} \) and \( \alpha_D \) are associated with variable costs. The effects of natural gas sales and number of customers on capital costs are expected to be positive and the effect of population density is expected to be negative. Guldmann (1983) uses a linear form with two consumer classes – residential and non-residential–for two gas utilities: Long Island Lighting Co (LILco) and East Ohio Gas Co (EOGC). He finds strong evidence on returns to scale with respect to natural gas sales. Guldmann (1989) found that a Box-Cox form dominated a linear form for four consumer classes: residential heating, residential non-heating, commercial, and industrial on a sample of 65 communities served by Peoples Natural Gas Co (PNGC), a pure distribution utility delivering service in Kansas, Nebraska, Iowa and Minnesota. His evidence on returns to scale with respect to sales is mixed. Guldmann and Hanson (1991) return to two consumer classes - residential and non-residential users and apply a Box-Cox specification on 240 observations for communities.
served by five different utilities in the U.S. Northeast. They found that marginal cost falls with residential sales and increases with non-residential sales.

We draw four conclusions from Guldmann's works which are germane to the current paper: first, annual sales by consumer classes have distinct effects on distribution capacity cost; second, there is mixed evidence in favor of increasing returns to scale as revealed by the relationship between distribution capacity cost and sales; third, the empirical evidence with respect to the effect of population density on cost is also mixed, and finally, the Box-Cox transformation is supported by the data, which implies that total distribution capital cost is not separable into linearly additive fixed and variable components. The latter result casts some doubt on the current practice of separating distribution capital cost into a fixed part which represents access and a variable part which is related to peak demand.

Although our paper shares the same objective as Guldmann's works i.e., to measure the main determinants of natural gas distribution capital costs as they enter the rate base, there are some significant differences: first, our measure of capital cost excludes consumer specific costs such as meters and links from street to building. There is little controversy about the allocation of such consumer specific costs to each consumer class and they are left out so that the fixed project costs could be separately identified in order to be in a position to measure the zero diameter access component. Second, we use estimated maximum daily demand by consumer class as explanatory variables rather than annual sales by consumer class. If consumer classes have different load factors over the sample, then the use of one or the other explanatory variable do not lead to identical regression results. Maximum daily demand is a more appropriate determinant since SCGM engineers informed us that the distribution network is designed to serve the latter which is obviously weather related. Third, pipeline length is incorporated explicitly as an explanatory variable. The delivery of the same amount of natural gas to customers who are located over a wider area, but who are otherwise identical, should obviously increase capital cost. Finally, to make sure that capital cost and maximum daily demand are properly related to each other, the sample includes only dead-end pipeline extension projects so that pipes receive the
dimension required to serve only the load over the given length with no load to be delivered further down the line.

Guldman interprets the left-hand-side variable of equation (1) as the capital costs of distribution extension projects. These are the costs which enter the rate base and which are converted into natural gas tariffs paid by users. To the extent that regulated distribution utilities are subject to the Averch-Johnson effect, these regulated costs do not reflect cost minimizing behavior and they are potentially subject to a capital intensive bias. The data used in the current study are open to the same criticism. This is why the capital cost would be more appropriately called regulated distribution capital cost. However the substitution possibility in favor of capital in laying natural gas distribution pipes appears rather limited and under these circumstances we expect the capital intensive bias to be small.

3- The Sample

The natural gas transmission network in the province of Québec was extended from Montreal Island to Trois-Rivières on the St-Lawrence River’s north shore, then on to Québec City with a spur line to Chicoutimi, and to Sherbrooke on the south shore with the assistance of government grants in the early eighties. These four regions, which are at least 100 km apart, were receiving natural gas for the first time. The local distribution networks were developed around the main transportation lines. In order to avoid the problem of having to allocate the cost of a given pipeline with multiple extensions, only self contained distribution pipeline extension projects are included in the sample implying a one to one relationship between a line and natural gas which travels through that particular line. This leaves us with a set of telescoping pipes which vary in diameter from 219 cm down to 42 cm. In order to analyze the main determinants of the regulated costs of local distribution pipelines, we need information on the cost of each project, its length, and the estimated maximum daily gas consumption over each segment.

3.1 Pipeline Distribution Cost
The cost information was obtained directly from two data files made available to us by SCGM. The first file includes the physical information on each project: diameter, length and type of materials (plastic and/or steel). The second file contains the cost information by year, materials, and size. The cost of each project was obtained by merging these two files. Costs, which are measured in 1986 Canadian dollars, include the expenditures on pipes and materials, trenches, pavements, workers, project design, and outside consultants; however the costs of meters and of service capital from street pipe to building are left out. We use the non residential construction price index to arrive at costs in constant dollars. This implies that changes in construction wage and in interest rate are explicitly taken into account through the price index.

3.2 Maximum daily demand

SCGM engineers design distribution pipeline capacity in order to be able to meet demand that would occur under 42 degree-days with a base temperature of 13\(^0\) C. Here is how degree-days (DD) are measured:

\[
DD = \begin{cases} 
0 & \text{if } T \geq 13^0 \text{ C.} \\
|T - 13| & \text{if } T < 13^0 \text{ C.}
\end{cases} \tag{2}
\]

The size of the pipe is a function of estimated daily demand which should occur under these rather extreme weather conditions. Hence, we need information on the estimated maximum daily demand by consumer class. There are three cases to be considered\(^{11}\):

i) Residential, commercial and medium stable consumption users: a separate linear regression model was applied to monthly consumption by all users of a tariff class located along a particular extension project as dependent variable and actual degree-days as explanatory variable.\(^{12}\) The estimated model was then used to infer maximum daily demand at temperature -29\(^0\) C.

ii) Large stable consumption users: the maximum daily natural gas withdrawal which is written in each consumer contract is used without modification.
iiii) Interruptible users: due to the nature of the interruptible service, there is no obligation on the part of the utility to deliver natural gas to these customers. So their demand should play no role with respect to pipe dimension. However, it can be seen from Figure 1 that interruptible users are very present during the peak heating season. In previous years, it has been the practice of SCGM not to cut service to interruptible users. For these reasons, the maximum daily withdrawal written in the interruptible user contract was also added in.

Aggregate maximum daily demand is the result of simply adding maximum daily demand across consumer classes for each pipeline extension project. SCGM engineers design the distribution network to serve this estimated maximum peak consumption.

Maximum daily demand reflects the behavior of natural gas customers who respond to natural gas rates. Hence there appears to be the possibility of simultaneous equations biases when maximum daily demand is used as an explanatory variable. This is not the case in the present sample: each extension project is approved by the PUC under the provision that there be no rate increase for other customers. Hence natural gas tariffs are considered as given when to the regulatory commission decides to approve or to refuse a given extension project.

Table 3 displays the average and the standard deviation of the variables in the four regions. The Québec region provides the largest number of observations (49) and Trois-Rivières the least (18). Altogether there are 131 observations from 1985-1995. Trois-Rivières has the highest average cost by project, the longest average pipe length and the largest number of customers by extension project. It can be seen that variability within and across regions is quite large. The exception is the average annual load factor which hovers around 35% across regions.

4- Model Specification and Estimation Results

Our model includes regional dummies, which represent region specific factors, estimated maximum daily demand, and pipeline length. After some unsuccessful estimation experiments due to multicollinearity, we did not consider estimated maximum daily demands by consumer
class as separate explanatory variables since there is no reason to expect that cost would respond
differently to peak usage by consumer class. After all a cubic meter of natural gas at the peak
period is the same for all customers. We have little a priori information on the functional form
linking regulated distribution pipeline costs and the explanatory variables and we use the linear
Box-Cox model while allowing for the possibility of heteroskedasticity associated with pipe
length. Under these assumptions, the model takes the following form:

$$\text{COST}_i (\lambda_c) = a_0 + a_{tr} \cdot D_{tr} + a_{sh} \cdot D_{sh} + a_{qc} \cdot D_{qc} + b \cdot \text{PEAK}_i (\lambda_p) + c \cdot \text{LENGTH}_i (\lambda_l) + u_i$$  (3)

where

- $\text{COST}_i$ = regulated capital cost of extension project $i$;
- $\text{PEAK}_i$ = estimated maximum daily demand over pipeline extension project $i$;
- $\text{LENGTH}_i$ = pipe length of extension project $i$;
- $D_s$ = dummy variable which takes value 1 if extension project takes
place in region $s$ and 0 otherwise, where $s = (tr, \text{Trois-Rivières})$, $(sh, \text{Sherbrooke})$ and $(qc, \text{Québec})$;
- $\lambda_j$ = Box-Cox transformation parameters;
- $Z(\lambda_j) = \frac{Z^{\lambda_j} - 1}{\lambda_j}$ if $\lambda_j \neq 0$;
  $= \ln Z$ if $\lambda_j = 0$;
- $a_0$, $a_s$, $b$, $c$ = set of structural parameters to be estimated;
- $u_i$ = error term;
- $E(u_i) = 0$
\[ E(u_i^2) = \sigma^2 e^{\delta \text{LENGTH}_i (\lambda_i)} \]

\[ \sigma^2, \delta, \lambda_i \] = parameters associated with the heteroskedastic variance.

Model (3) is estimated by applying the maximum likelihood principle under the assumption that error terms are mutually independent and that they follow a normal distribution with an heteroskedastic variance. The results appear in Table 4. It is seen that none of the Box-Cox transformation parameters is statistically significant and a likelihood ratio test does not reject the null hypothesis that the model has a log-linear form with a homoskedastic variance.

The acceptance of the log-linear function indicates that total cost cannot be separated into linearly additive fixed and variable components. This results casts further doubt on the validity of the current practice of PUC to separate regulated capital cost into linearly additive fixed and variable components. Trois-Rivières and Sherbrooke are low cost regions relative to Chicoutimi while Québec is a high cost region. The latter result is expected since Québec has the largest and oldest urban area in this study with special pavement requirements. The two main results are that the elasticity of total cost with respect to maximum daily demand is very low and that the elasticity with respect to pipe length is slightly less than one. In economic terms, we find very large economies of scale to additional sales at the very narrow peak period for a given pipe length, but we find limited economies of scope to laying additional pipes for a given maximum daily demand.

The implications of these regulated cost estimation results can be seen in Table 5, which shows the estimated regional marginal costs of maximum daily demand (¢/m³) and of pipe length ($/km) assessed at sample averages. The marginal cost of additional maximum daily demand is less than one cent per cubic meter; this marginal cost estimate is very low and well below average cost. In terms of the cost of laying pipes, the Québec region has the highest marginal cost per kilometer, i.e., $167 464 and the Trois-Rivières region, the least at $92 874. This result indicates that less attention should be directed at the role played by maximum daily demand and...
more at the way that the consumers are located along the pipelines since it is pipeline length which matters the most.

**Conclusion**

In this paper, we use observations on the rapid expansion of the natural gas distribution network into virgin regions of the province of Québec to estimate the effects of natural gas maximum daily demand and pipeline length on natural gas distribution capital costs. The cost elasticity with respect to maximum daily demand is not significant, while the cost elasticity with respect to pipe length is slightly less than one. Thus, we find that it costs little to add load even at the very narrow peak period over a given length while extending a line leads to little cost savings per kilometer.

Although regulators would like to divide these costs into a fixed or access charge and a variable component reflecting usage costs, we find that the total distribution capital cost by extension project is not separable into two linearly additive components with fixed and variable parts. Thus, we find little empirical support for the public utilities commission’s current practice with respect to the allocation of distribution capital costs. Rather natural gas distribution pipelines as they have been designed and approved under the regulatory process give rise to almost no cost elements which are directly related to maximum daily demand. So incorporating distribution capital cost aspects in the variable part of the tariff structure makes prices too high in terms of economic efficiency. Distribution capital costs should appear in the fixed part of the tariff.

We are still left with the problem of allocating costs to customers which are spread along the lines. In a simple situation where customers have the same size and are evenly spaced, then the case can be made for an equal fixed charge per customer. However, if customers have unequal size and if they are unevenly distributed along the line, then the problem becomes more complex. Consumer surplus for each consumer class should be taken into account to determine whether laying a pipe is worthwhile and this sets constraints on the fixed part of the tariff.
However there is a fair amount of discretion left to incorporate into tariff schedules other dimensions related to equity, pressure groups, industrial policies, and so on. That is what makes the lives of P.U.C. commissioners interesting.
Figure 1

SCGM Monthly Natural Gas Deliveries
May 1994 - April 1995

Deliveries (10^6 m³)

Month

May
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
March
April
TABLE 1
SCGM Income Statement and Assets in 1995 (millions of Canadian Dollars)

I- **Income statement**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross Revenue</td>
<td>1133</td>
</tr>
<tr>
<td>Cost</td>
<td></td>
</tr>
<tr>
<td>Natural gas and transport to Quebec</td>
<td>673*</td>
</tr>
<tr>
<td>Operating Expenses</td>
<td>150</td>
</tr>
<tr>
<td>Interest and Depreciation</td>
<td>175</td>
</tr>
<tr>
<td>Net Income</td>
<td>135</td>
</tr>
</tbody>
</table>

II- **Assets**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Assets</td>
<td>1760</td>
</tr>
<tr>
<td>Net Fixed Assets</td>
<td>1372</td>
</tr>
<tr>
<td>Distribution Assets</td>
<td>1217</td>
</tr>
</tbody>
</table>

* Item not subject to regulation by Québec PUC (Régie de l'énergie)
## TABLE 2

**SCGM, Tariff classes, 1995-96**

<table>
<thead>
<tr>
<th></th>
<th>General</th>
<th>Stable Consumption</th>
<th>Interruptible</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential</td>
<td>Commercial</td>
<td>Medium</td>
<td>Large</td>
</tr>
<tr>
<td>Number of customers</td>
<td>114 930</td>
<td>34 361</td>
<td>568</td>
<td>119</td>
</tr>
<tr>
<td>Sales, 10^6 m^3</td>
<td>839</td>
<td>1 410</td>
<td>371</td>
<td>1 800</td>
</tr>
<tr>
<td>Transportation and distribution average rate, $/m^3</td>
<td>23</td>
<td>19</td>
<td>12</td>
<td>7</td>
</tr>
</tbody>
</table>

Note: Natural gas (commodity) price is not regulated.

Source: SCGM, 1995-1996 budget
**TABLE 3**

Natural gas distribution pipeline extension: sample average and standard deviation

<table>
<thead>
<tr>
<th>Region</th>
<th>Trois-Rivières</th>
<th>Sherbrooke</th>
<th>Québec</th>
<th>Chicoutimi</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost ($1000 Canadian)</td>
<td>1655</td>
<td>1304</td>
<td>1144</td>
<td>962</td>
<td>1235</td>
</tr>
<tr>
<td></td>
<td>(2122)</td>
<td>(1310)</td>
<td>(1380)</td>
<td>(1006)</td>
<td>1430</td>
</tr>
<tr>
<td>Peak consumption (m³)</td>
<td>34139</td>
<td>45502</td>
<td>35670</td>
<td>17479</td>
<td>35770</td>
</tr>
<tr>
<td></td>
<td>(51305)</td>
<td>(69665)</td>
<td>(54295)</td>
<td>(24610)</td>
<td>(56387)</td>
</tr>
<tr>
<td>Average length (km)</td>
<td>19.4</td>
<td>11.5</td>
<td>6.8</td>
<td>7.8</td>
<td>10.2</td>
</tr>
<tr>
<td></td>
<td>(26.5)</td>
<td>(11.8)</td>
<td>(9.2)</td>
<td>(8.4)</td>
<td>(14.0)</td>
</tr>
<tr>
<td>Number of observations</td>
<td>18</td>
<td>43</td>
<td>49</td>
<td>21</td>
<td>131</td>
</tr>
<tr>
<td>Number of customers</td>
<td>269</td>
<td>104</td>
<td>120</td>
<td>113</td>
<td>134</td>
</tr>
<tr>
<td>Annual load factor (%)</td>
<td>34</td>
<td>37</td>
<td>32</td>
<td>37</td>
<td>36</td>
</tr>
</tbody>
</table>

Source: SCGM and calculations by the authors
## TABLE 4

Regression results

<table>
<thead>
<tr>
<th></th>
<th>Coefficient</th>
<th>Standard Error</th>
<th>t-Value</th>
<th>p-Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\lambda_c$</td>
<td>-0.008</td>
<td>(-0.20)</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>$\lambda_p$</td>
<td>0.278</td>
<td>(0.86)</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>$\lambda_l$</td>
<td>-0.032</td>
<td>(-0.81)</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>$a_0$</td>
<td>2.60</td>
<td>(16.92)</td>
<td>2.56</td>
<td>(75.05)*</td>
</tr>
<tr>
<td>$a_{tr}$</td>
<td>-0.190</td>
<td>(-3.16)</td>
<td>-0.196</td>
<td>(-4.92)*</td>
</tr>
<tr>
<td>$a_{sh}$</td>
<td>-0.073</td>
<td>-1.78</td>
<td>-0.064</td>
<td>(-1.94)*</td>
</tr>
<tr>
<td>$a_{qc}$</td>
<td>0.320</td>
<td>(4.71)</td>
<td>0.351</td>
<td>(10.49)*</td>
</tr>
<tr>
<td>$b = \text{Peak}$</td>
<td>0.023</td>
<td>(1.51)</td>
<td>0.017</td>
<td>(1.54)**</td>
</tr>
<tr>
<td>$c = \text{Length}$</td>
<td>0.960</td>
<td>(8.62)</td>
<td>0.961</td>
<td>(74.26)*</td>
</tr>
</tbody>
</table>

### Heteroskedasticity structure

<table>
<thead>
<tr>
<th></th>
<th>Coefficient</th>
<th>Standard Error</th>
<th>t-Value</th>
<th>p-Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\delta$</td>
<td>-0.18</td>
<td>(-1.10)</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>$\lambda_{x_1}$</td>
<td>-0.393</td>
<td>-0.70</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>Log-likelihood</td>
<td>-425.3</td>
<td>-428.0</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note:  
* statistically significant at 5%  
** statistically significant at 10%
**TABLE 5**

Marginal Costs Evaluated at the Sample Means

<table>
<thead>
<tr>
<th>Region</th>
<th>Maximum daily demand $/m^3$</th>
<th>Length $/km$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trois-Rivières</td>
<td>0.96</td>
<td>92,874</td>
</tr>
<tr>
<td>Sherbrooke</td>
<td>0.50</td>
<td>108,714</td>
</tr>
<tr>
<td>Québec</td>
<td>0.58</td>
<td>167,464</td>
</tr>
<tr>
<td>Chicoutimi</td>
<td>0.95</td>
<td>115,784</td>
</tr>
</tbody>
</table>
NOTES

1- Consumers can still purchase natural gas from their local distribution utility which then acts as broker.

2- All values are expressed in Canadian dollars.


4- Ibid p. 12.

5- Ibid p. 95.

6- Gazifère distributes natural gas within three Québec municipalities near the capital region of Ottawa, i.e., Hull, Gatineau and Aylmer.

7- For a thorough review up to the early eighties, see Joskow and Schmalensee (1983).

8- Although Guldmann assumes that population density has a negative effect on distribution capital costs because shorter pipes are required to deliver a given amount of natural gas, it is not necessarily so because land is more valuable and it costs more to open trenches in densely populated areas. When we control for pipe length, as it is done in this paper, it is not clear what effect population density should have on distribution capital costs.

9- Besides population density, the utility load factor and distribution utility wage rate appear as additional explanatory variables in this particular case.

10- This point will be addressed further in the section 3.2.

11- See Table 2 for the five consumer classes.

12- A quadratic linear model was also estimated and it led to no improvement in terms of goodness of fit.

13- We used several devices to test the presence of heteroscedasticity in the linear form of the model. Among others, Breusch-Pagan tests and White's test all lead us to conclude that only pipe length affects the error variance.

14- Other functional forms of the model and the heteroscedastic variance have been estimated, but they led to no statistical improvement. Elasticities computed at the variable means vary little with the model specification. Estimation is performed with computer program TRIO.
REFERENCES


