REDESIGN OF THE SUPPLY, TRANSPORTATION AND LOAD-BALANCING SERVICES, PHASE 2B, PART 1

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BACKGROUND

Since November 2013, the generic file on (Énergir, s.e.c.) Énergir's cost allocation and rate structure has been in progress with the Régie de l'énergie (the Régie). Phase 1, dealing with the allocation of distribution costs, was completed in December 2017. Subsequently, in August 2018, the file review of Phase 2 was temporarily suspended pending a report prepared by an expert appointed by the Régie. On November 20, 2019, the report by the independent firm Elenchus Research Associates Inc. (Elenchus) was filed, reactivating the review of the rate structure. Phase 2A, described as a priority because of significant deferred costs and relating to the functionalization of the Champion pipelines, led to a decision by the Régie in the spring of 2020.

Phase 2B involves the redesign of supply, transportation and load-balancing services. The working sessions held with Elenchus helped clarify the vision presented and the expert's interpretation of Énergir's evidence. To this end, Énergir proposes to amend the initial evidence in the file by incorporating the three-step method of functionalizing gas supply costs suggested by the expert. In addition, Énergir fleshing out the issues that Elenchus identified as requiring additional explanation to allow for a thorough assessment of the proposal, such as the handling of year-end overpayments and shortfalls. Lastly, Énergir is responding to some follow-ups on decisions related to the evidence studied in this phase, which have been added since the old documents were filed.

To facilitate the production of evidence by Énergir and its consideration by all participants, it was agreed, in accordance with the letter[1] sent by the Régie on May 25, 2020, that only one updated and translated set of exhibits needed to be filed. The evidence is divided into two parts, identified in decision D-2020-006.[2] Part 1 is addressed in this document and in Gaz Métro-5, Document 13, while Part 2 is addressed in Gaz Métro-5, Document 14.

[1] R-3867-2013, Phase 2, Exhibit A-0260, letter dated May 25, 2020.
[2] Paragr. 78.

This document outlines the new conceptual framework in Section 1 and a comprehensive study of the causality of supply costs in Section 2. The theoretical portion of the evidence is continued in Section 3, which covers the topic of the average demand and excess approach, to permit reconciliation between theory and practice in Section 4. This leads to the final sections, 5 to 7, which contain a review of the proposed methods for the functionalization, classification and cost allocation for supply, transportation and load-balancing services.

Énergir would like to remind the reader that the updated method of functionalizing gas supply costs using a three-tier approach does not go against the foundations of the comprehensive study on the overhaul of the interruptible service contained in original exhibit B-0134: Gaz Métro-5, Document 2. In fact, the concept of considering interruptible to be a tool to help reduce overall supply costs – rather than a service – remains the same. The interruptible supply cost is no longer assigned to a particular type of distribution customer (unlike the current Rate D_5 category) since it benefits all customers that obtain their supplies from Énergir and because the contribution of interruptible customers is recognized only in the load-balancing rate in the form of credits. That is why Énergir would like to refer the reader to exhibit Gaz Métro-5, Document 13 on the topic of the overhaul of the interruptible service.

It is worth mentioning that most of the original evidence[3] has been retained but reorganized so that it flows in a logical manner. Where the proposal differs from what has been presented in the past, the reader is alerted, and an explanation of the change is provided.

[3] R-3867-2013, Phase 2, Gaz Métro-5, Document 1 to Gaz Métro-5, Document 11 (excluding Documents 4 and 6) [B-0133, B-0134, B-0136, B-0485, B-0188, B-0331, B-0332, B-0334 B-0474].

1. INTRODUCTION TO THE NEW CONCEPTUAL FRAMEWORK

1.1. OBJECTIVES

Énergir is targeting three major review objectives in this evidence which support the new proposed conceptual framework:

- Conduct a complete analysis of the causation of costs associated with the supply chain.
- Reviewing all functionalization, allocation and pricing of supply, transportation and load-balancing services to adapt them to the new supply environment.
- Respond to various follow-ups requested by the Régie about the supply chain, using a global solution.

Analysis of Cost Causation

To review or modify the rate setting structure of a service, we need to understand the source and causation of the inherent costs of that service. The supply cost causation was analyzed at the time of rate unbundling in the early 2000s.The analysis allowed for establishing the basic cost functionalization principles for the transportation and load-balancing services. In decision D-97-047, the Régie chose the average and excess demand method. This method will be discussed later in Section 3.

At that time, the transportation capacities contracted by Énergir were almost entirely comprised of firm transport long haul (FTLH) between Empress and the franchise. The supply was purchased daily, on a relatively stable basis, and, depending on the season, sent directly to the customers, to franchise storage sites or to the Union Gas storage site at Dawn. Over the years, in order to generate considerable savings for customers, the supply structure was moved to Dawn. As a result, purchases at Dawn have increased and FTLH transportation capacities have been relaxed or replaced, in part, by firm transport short haul capacities (FTSH) between Dawn or Parkway and the franchise.

As the changes occurred, further modifications were made to the functionalization methods among the services.[4] However, before making other adjustments in response to the follow-ups requested by the Régie, Énergir believes it is time to re-examine the basic principles of these methods by analyzing the cost causation in the supply environment that was updated when the supply structure was moved to Dawn. Section 2 will present this analysis.

Review the pricing of the services

Once the causal links are examined, the rate-setting structure can be reviewed and changes can be proposed, if required.

The principles for setting new rates for the supply, transportation and load-balancing services are essentially the same as for establishing the distribution rates. These principles were presented in the 2012 Rate Case.[5] They include fairness and simplicity.

A rate is considered fair if the applicable price for the customer is lower than the standalone cost and higher than the marginal cost associated with it. This principle was mentioned by Dr. Overcast in Phase 1 of this case:

> "*Theoretical economists have developed the theory of subsidy free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy free, in the economic sense, so long as the price exceeds marginal cost but is less than standalone costs (SAC). Indeed all of this theory provides useful insight to the regulatory process where, as a practical matter, costs must be allocated between classes of service and within classes of service. For example, if the process of cost allocation results in rates that exceed standalone costs for some customers or class of customers, prices must be set below the standalone cost but above marginal cost to assure that those customers make the maximum practical contribution to common costs.*"[6]

For the distribution service, the difference between the marginal cost and the standalone cost is large due to the distributor's considerable economies of scale. This allows Énergir to distance itself, if required, from the cost of service study to take other considerations into account (competitive position, commercial aspects, etc.). For the supply, transportation and load-balancing services, there is little room for manoeuvre between the marginal cost and the customer's standalone cost (or the cost of providing their own service). To be fair, the rates must therefore reflect the costs more accurately. Énergir therefore tries to bring the rates closer to the

[4] For example, see R-3752-2011, Gaz Métro-12, Document 1.
[5] R-3752-2011, Gaz Métro-13, Document 8, section 2.2.
[6] R-3867-2013, Phase 1, B-0005, Gaz Métro-1, Document 1, p. 4.

causal link. Énergir would like to point out that the goal of unbundling rates was to offer customers a wider range of choices for more effective management of their energy needs, without benefiting some customers at the expense of others. A clear price signal had to be sent to customers for services that they could contract directly from external suppliers. For unbundled services, however, the user-pays principle had to be respected. That way customers could directly compare the price of Énergir's supply services (supply, transportation and load-balancing) with market prices.

Sections 5 to 7 present the proposed changes to the methods for functionalizing, classifying and allocating gas supply costs. The final steps in the pricing process, which consist of setting rates that are as close as possible to the rates that would be applied using the methods chosen in previous stages, as well as to the changes required by the *Conditions of Service and Tariff* (CST), are presented in the exhibit titled Gaz Métro-5, Document 14.

In the course of its reflections, Énergir also tried to simplify the rate-setting structures, where possible. Simple rate-setting structures send the customers a clear price signal while facilitating management and limiting administrative costs. The quest for simplicity must not run counter to the fairness principle, however.

<u>Response to follow-ups requested by the Régie</u>

The Régie requested several follow-ups concerning the supply, transportation and load-balancing services. An isolated examination of these topics is not optimal and may lead to contradictory solutions. A full review of the cost causation and the rate-setting structures allowed Énergir to respond to the Régie's follow-up requests with a consistent and global solution. The follow-ups requested by the Régie are therefore added to the evidence based on the issues involved.

1.2. Proposed conceptual framework

The starting point for the reflection and the numerous analytical studies in connection with the application for review of gas supply services is the inter-relatedness of supply costs. Since the tools that generate these costs are interchangeable—that is, they are not purchased for a particular service, but rather for overall demand—the cost of each tool for transportation and load-balancing services should not be directly separated. Énergir therefore proposes to present supply costs as a whole, rather than by service. In theory, the new conceptual framework involves directly functionalizing supply costs between services (supply, transportation and load-balancing) by referring to their "direct functions" rather than the "indirect tools" used to deliver these services. This new conceptual framework must be understood before one can fully grasp its impact on all the elements proposed by Énergir in its demonstration.

Énergir's proposal is a comprehensive, integrated solution that addresses all aspects related to supply, transportation and load-balancing services. This proposal not only makes it possible to set rates that are more representative of cost causation, but also to be more suitable for the current supply structure, while being flexible enough to respond to future changes.

2. Cost causation

The supply, transportation and load-balancing rates attempt to allocate and price, as accurately as possible, the costs caused directly by the customers. Examining the cost causation is therefore crucial before studying the pricing of the various services, ultimately leading to service pricing that will enable the recovery of these costs through revenues.

The gas supply is defined essentially by two major components: the purchase of the commodity and its transportation to the franchise, in light of the customers' daily needs. The causation is therefore examined by addressing each of the components separately.

Load-balancing is not, in itself, a component of the supply cost, but rather a rate-setting component. In fact, the supply tools are always purchased to meet a total demand that encompasses both transportation and load-balancing needs, not to meet a need arising from only one or the other. This means that the same supply tools may be used to meet the transportation need and the load-balancing need of customers The examination of the cost causation for supply and transportation specify which types of consumer profiles generate which costs and allow us to functionalize the costs among the services, discussed in sections 5 and 6.

2.1. TRANSPORTATION COST CAUSATION

To examine the causation of the cost of delivering natural gas to the franchise, the following assumptions were made:

- There is no constraint on the purchase of the commodity, i.e. the commodity is considered to be available at all times at the same price, from any purchase point.
- There is no constraint on the volume that can be received by the distribution network.
- There is no operational flexibility constraint related to changes in the demand over the course of a day.

The supply environment in which Énergir operates must also be taken into account. In other words, supply purchase and transportation capacity go hand in hand. Almost all supply purchases are accompanied by a transportation service since there is no direct in-franchise source of supply, with the exception of renewable natural gas.

These assumptions allow the specific causation of the transportation costs to be evaluated separately from the other variables.

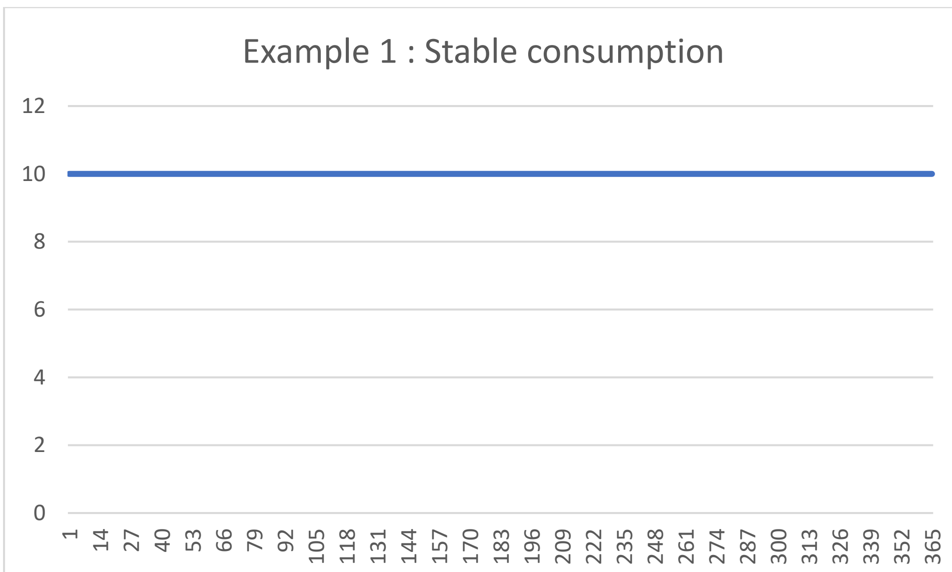
In the evaluation of the cost causation, the diagrams produced are always in order of highest to lowest consumption over the year.

Finally, since the only transportation network in Canada that connects to supply points in Québec is TransCanada PipeLines Limited (TCPL), all the scenarios using transportation tools will be made in consideration of the fact that the TPCL firm transportation tools cannot be purchased seasonally (for a period of less than 12 months).

2.1.1. Stable volume vs. seasonal volume

To begin the evaluation of the cost causation from the simplest illustration, let us start with the transportation costs for a customer with 100% stable consumption.

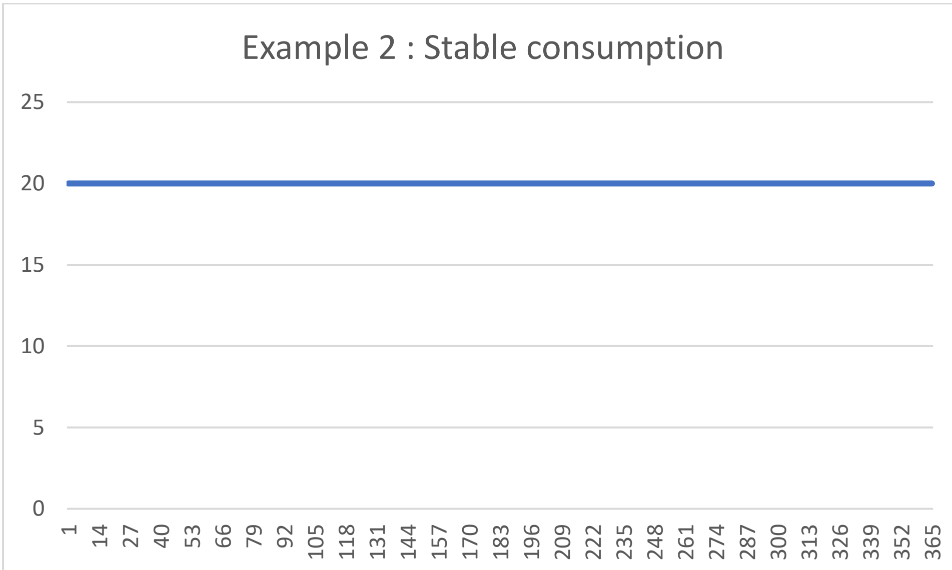
Graph 1



This consumer must deliver 10 units per day from the place where it purchased the supply to the consumption location. In total, this customer will consume 3,650 units a year. Each transportation unit purchased will therefore be used to transport and consume natural gas. At a purchase cost of $1 per transportation unit, the total cost to transport the supply is $3,650, which also comes to $1 per unit consumed.

What would happen if the next year the customer doubled its production but maintained a 100% stable consumption profile?

Graph 2

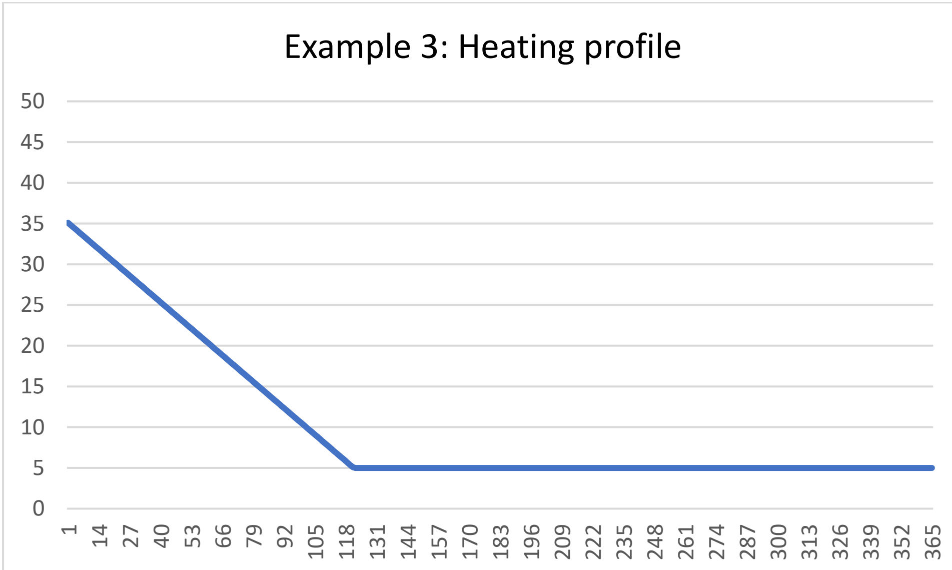


The customer would then have to deliver 20 units per day from the supply purchase location in order to consume it. In total, the customer would consume 7,300 units per year. Once again, each transportation unit purchased would be used to transport and consume natural gas. Still at a purchase cost of $1 per transportation unit, the total cost for transporting the supply would increase to $7,300, which is again $1 per unit consumed.

So if all Énergir's customers had 100% stable consumption, the volume consumed would perfectly represent the cost causation. However, given that a significant number of Énergir's customers do not have stable consumption, we have to examine whether the cost causation is the same for customers who do not have 100% stable consumption.

Let us return to example 1 where the customer consumed 3,650 units per year, but now suppose that the customer profile is not stable.

Graph 3

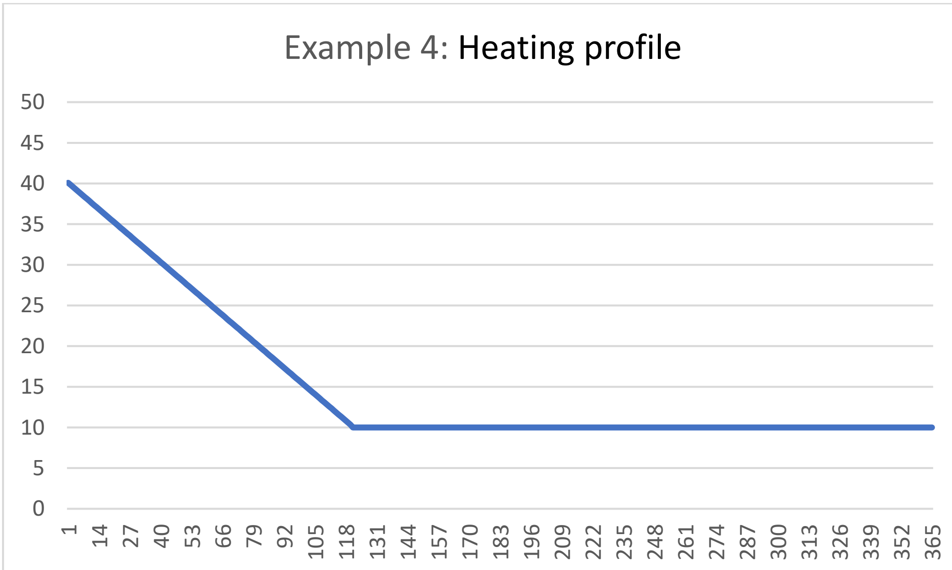


In this case, the customer needs at least 5 units a day, but may need 35 units on the coldest day of winter. It must therefore deliver 5 units per day outside the heating period and an increasing number of units during the winter, from 5 to 35 units per day. Since the only available supply tool is transportation on an annual basis, as mentioned in the initial assumptions, this customer has to purchase transportation capacity equal to 35 units for 365 days of the year in order to deliver 35 units on the coldest day. So even though its consumption is only 3,650 units (as it was in the first example), the total cost for transporting the supply will be $12,775 ($35 \times 365$), which comes to $3.50 per unit consumed ($12\,775 \div 3\,650$). Of a total purchase of 12,775 transportation units in the year, 3,650 will be used and 9,125 will be unused. This unused transportation portion corresponds to the customer's load balancing need.

Therefore, the more stable the customer's consumption profile, the fewer unused transportation units there are and the lower the unit cost per unit consumed.

To illustrate this situation, here is a scenario in which the customer with a heating profile adds stable consumption equipment to increase its basic consumption from 5 to 10 units a day.

Graph 4



The customer now needs at least 10 units per day but may need 40 on the coldest day of the winter. It will have to deliver 10 units per day outside the heating period and an increasing number of units during the winter, from 10 to 40 units per day. To be able to deliver 40 units on the coldest day, this client will have to purchase transportation capacity equal to 40 units for all 365 days of the year. Although its total consumption will be only 5,475 units ($3\,650 + 5 \times 365$), the customer's total cost to transport the supply will be \$14,600 (40×365), or \$2.67 per unit consumed ($14\,600 \div 5\,475$). Of a total purchase of 14,600 transportation units in the year, 5,475 units will be used and 9,125 will be unused.

By increasing its proportion of stable consumption, the customer increases its total transportation cost from \$12,775 to \$14,600, but the cost per unit consumed decreases from \$3.50 to \$2.67. This cost reduction per unit can be explained by the fact that the increase in stable volume does not increase the unused transportation units. This number remains constant at 9,125 units, despite the overall increase in consumption and the increase in the customer's peak use.

The change in the cost per unit can also be explained by the change in the customer's load factor (LF). The LF is the measure of the customer's consumption stability. It represents the total number of units required to serve the customer and is calculated as follows:

$$LF \ = \frac{Actual\ consumption}{Maximum\ potential\ consumption} = \frac{Average\ consumption}{Peak\ consumption}$$

Before the increase in basic consumption, the customer’s LF was 3,650 units consumed of a potential of 12,775 units, or 28.6%. After the increase in basic consumption, its LF rises to 5,475 units consumed of a potential 14,600 units, or 37.5%.

While for customers with a stable consumption profile, the cost per unit consumed remains the same no matter what volume is consumed, this cost varies for customers that do not have a 100% stable profile. The closer the customer’s LF is to 100%, the closer its per-unit cost will be to the stable profile customer’s cost. The closer the LF is to 0%, the higher the number of unused transportation units and therefore the further its per-unit cost from the stable profile customer’s cost.

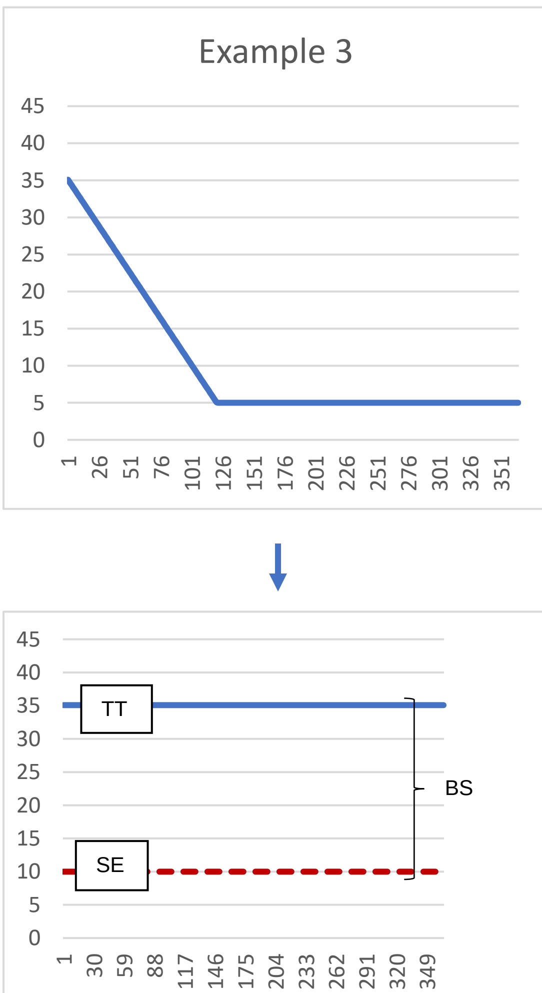
More specifically, for all customers, the cost per unit varies based on the number of used and unused transportation units. When the customer has 100% stable consumption, no matter what the volume is, the cost per unit consumed remains the same: there are no unused transportation units. When the consumption is not stable, then the per-unit cost changes based on the stable portion of the consumption and the number of unused transportation units.

In examples 3 and 4, the number of unused transportation units is the same, and the total cost of the unused units is the same in each case, but since the stable consumption is higher in example 4, this total cost is divided over a greater number of units consumed, which lowers the cost per unit consumed.

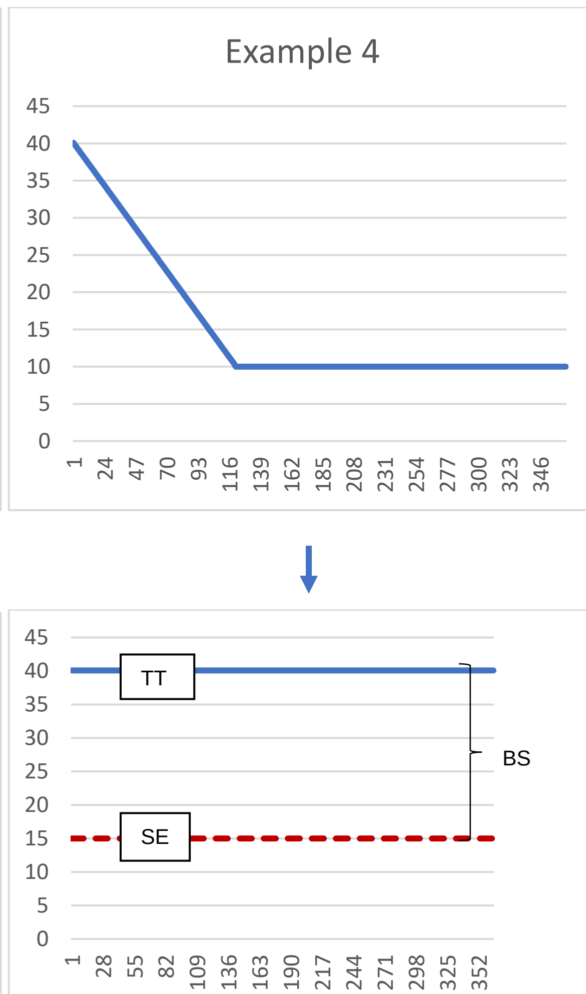
The causation of the supply cost for delivering natural gas from the purchase location to the distribution network therefore depends solely on the ratio between the used and unused transportation units. When a customer has a LF of 100%, the transportation costs are optimal. Any lower LF automatically leads to unused transportation units, which increases the cost per unit consumed.

Let us return to examples 3 and 4 to determine whether it is possible to systematically subdivide the costs to isolate the effect of the units consumed and the unused units.

Graph 5



Graph 6



The costs of each profile can be represented differently. Stable equivalent consumption (SE), represented by the dotted red line, corresponds to the transportation units required each day to meet the customer's total consumption need. The solid blue line represents total tools (TT) to purchase to meet the customer's peak need. The gap between the blue line and the red line allows us to calculate the seasonal need (SN) we need to meet.

In each case, the total number of used and unused units is the same, regardless of the graphic representation of the customer's needs. Based on the new diagram, the customer in example 3 has a stable equivalent consumption of 10 units per day, for a total of 3,650 units. The peak is set at 35 units per day, or 25 units more than the stable equivalent consumption. For the entire year, 25 unused units per day represents a total of 9,125 unused units. These results are the same as those obtained in the original diagram of the consumption profile (Graph 3).

As for the new diagram of the example 4 profile, the stable equivalent consumption is 15 units per day, for a total of 5,475 units. The peak is 40 units per day, which is 25 units per day above the stable equivalent consumption. Once again, these 25 unused units per day equal 9,125 unused units for the year.

In both cases, the customer's consumption to establish a stable equivalent portion is equal to the customer's average consumption per day. The LF is obtained by dividing the average consumption by the peak consumption or the used units by the total units required to supply the customer. The LF rises from 28.6% in example 3 to 37.5% in example 4.

The consumption profile diagram uses two straight lines to isolate the stable equivalent consumption while maintaining the relative measure of the cost of the additional units required to supply the customer. Using the new diagram, the gap between the peak need and the average consumption is 25 unused units in both example 3 and example 4. This discrepancy clearly shows that in each example, the total number of unused units is 9,125 units. The total cost allocated to balance the consumption of these two profiles should therefore be the same, despite a different total consumption.

So the cost of the units used by the customer is still comparable ($1/unit in examples 3 and 4). To show the cost causation, this portion must be allocated based on the volume consumed by the customer.

However, at equal consumption, the weight of the excess units that are not used to transport the supply changes based on the customer's LF. The lower the LF, the more seasonal the customer's consumption and the higher the unused transportation costs. The average and excess demand method retained when the services were unbundled[7] creates this same dynamic and allows us to conclude that the supply costs must be split between transportation and load-balancing services based on a LF equivalent to 100%. An in-depth review of this principle is carried out in Section 3.

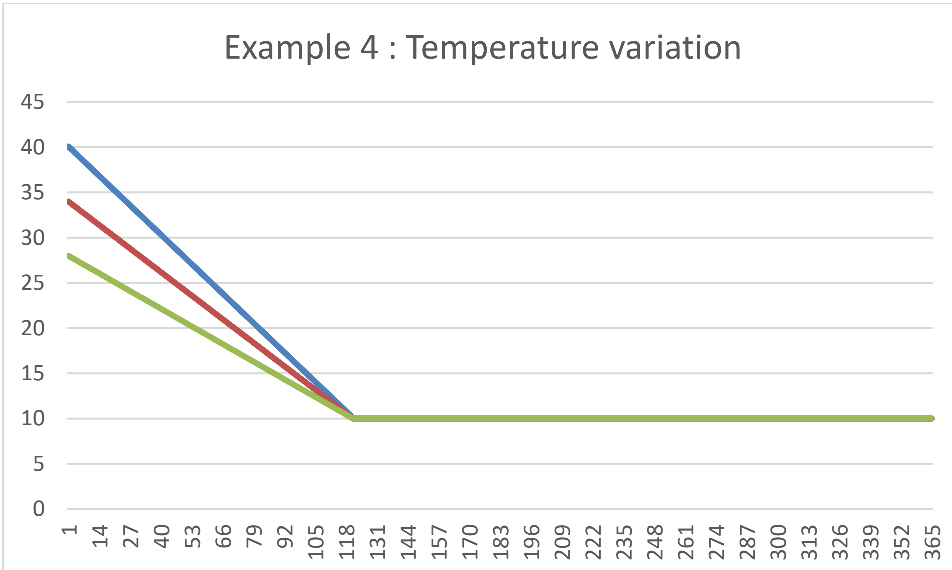
2.1.2. Use of the real vs. projected profile

The profiles presented until now have been rather simple. In reality, however, the annual need of a customer with a seasonal profile will generally vary based on the temperature. The warmer the winter, the less the customer will consume, but the colder the winter, the more it will consume. Is the choice of real or projected profile important? How will it affect the dynamic we saw earlier?

To illustrate this situation, let us return to example 4 and add a temperature variation.

[7] Decision D-97-047. In this decision, the Régie retained the average and excess demand method proposed by Sharon L. Chown, on behalf of Approvisionnement Montréal, Santé et Service Sociaux (AMSS), in case R-3323-95.

Graph 7

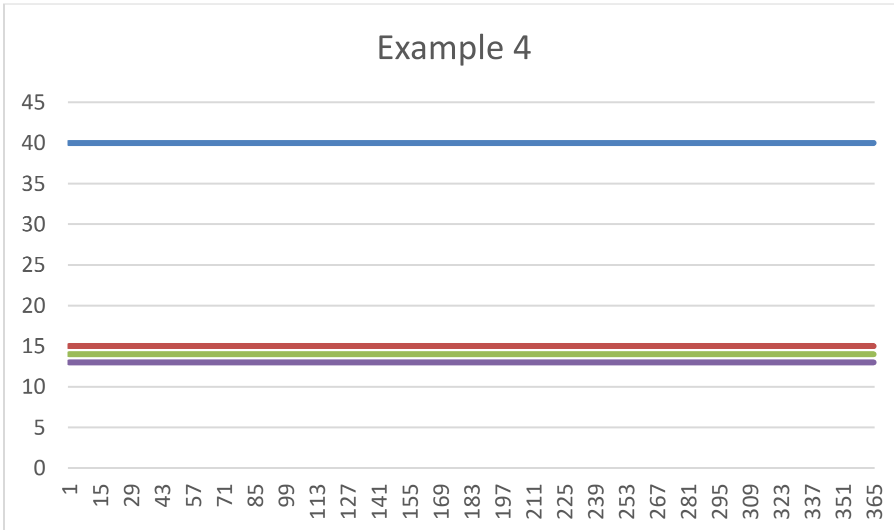


The customer will consume different total quantities based on a cold winter (blue line), a normal winter (red line) and a warm winter (green line). But no matter what the real consumption is, the client’s peak need is always based on its potential consumption for the most extreme temperature during a cold winter, or 40 units. This means that, in every scenario, the customer will need to purchase transportation tools totalling 14,600 transportation units () to secure its supply. Furthermore, the customer’s supply cost will remain steady at $14,600, whether the winter is cold or warm. However, depending on the winter, the number of used and unused units will vary.

In the cold winter scenario – the one used to determine the maximum need – the used and unused units are those shown in example 4: 5,475 used units and 9,125 unused units. If the temperature is milder, however, we get a different ratio. In a normal winter, the used units drop to 5,110 and the unused units increase to 9,490. Finally, in a warm winter, the number of used units is just 4,745, while the number of unused units increases again to 9,855. So the less cold the winter in comparison to maximum need, the more unused units the customer’s profile generates.

To determine the customer's stable equivalent portion, we can show all these graphs with straight lines, as in Graph 5 and Graph 6:

Graph 8



Depending on the winter, the number of unused units ranges from 27 units per day in a warm winter (40 – 13) to 25 units per day in a cold winter (40 – 15). To correctly allocate the costs, the customer's real use of transportation tools, not the projected use, gives the real number of unused units by this customer for a given year. If we use the projected parameters, rather than the real value, the units allocated under the stable equivalent portion will no longer give a LF of 100%.

For example, suppose that the number of units expected to be used in the rate case at a normal temperature for this customer is set at 14 per day, at a cost of $1/unit. The profile considered to be stable therefore has an average cost of $14/day. If, in fact, the winter is warmer or colder than normal, then the $14 cost will no longer be equal to a stable profile. For a cold winter, the stable profile would be worth $15/day. To achieve a balance between revenues and costs, since 15 units per day will be consumed even though the cost was established based on a stable consumption of 14 units, the rate would have to be $0.93/unit (14 $ ÷ 15 units) to exactly recover the allocated costs. But the real cost per unit is $1. This means that when the rate is established in advance at $1, an excess rate of $0.07 per unit is generated in comparison to a stable profile with a LF of 100%, whereas the real excess should have been 0. a warm winter would have the reverse effect for this customer.

Since the temperature changes every year, for the cost causation to be as accurate as possible, the real consumption profile must be used to calculate the stable equivalent consumption profile. Otherwise, the costs would be automatically allocated based on the wrong consumption profile (stable vs. seasonal), depending on whether the winter was colder or warmer than normal.

In conclusion, the allocation of costs based on actual used and unused transportation units allows us to properly split the total costs of natural gas transportation between the stable equivalent consumption profile and a seasonal consumption profile. The real profile must be used, because it is the only one that reflects the effect of temperature on the client's consumption. Full examples of year-end findings, applicable to all customers, are presented in Section 6. The handling of year-end overpayments and shortfalls is illustrated.

2.1.3. Costs based on consumption profile

The allocation of costs based on used and unused units accurately portrays the cost causation of delivering the supply, no matter what the customer's profile is. In terms of the stable equivalent portion, the allocation is the same for all units consumed. In terms of the portion allocated on the basis of a seasonal consumption profile, however, the incidence of the cost per unit consumed reflects the profile of each customer. A closer examination of the incidence of the cost of different profiles is therefore necessary to understand how the seasonal profile influences costs.

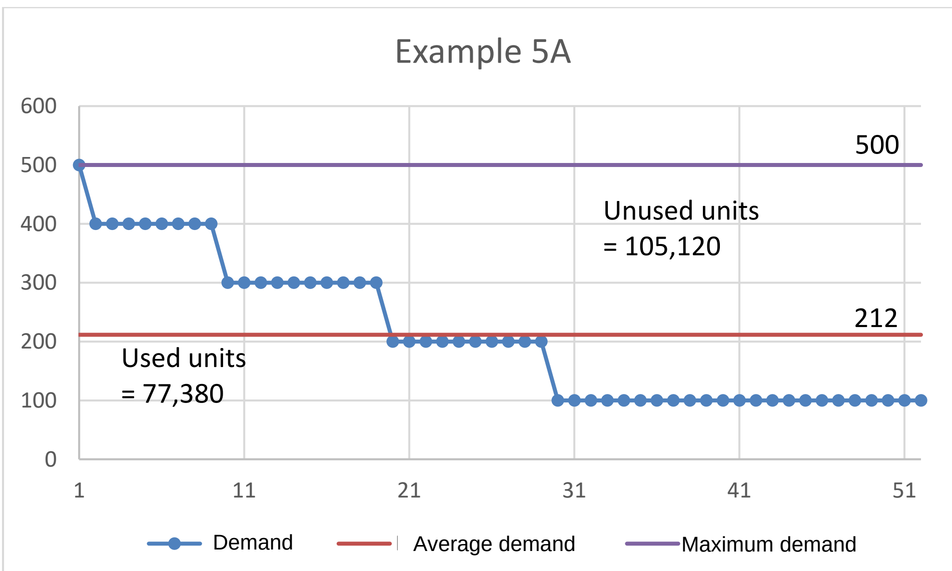
Cost causation will be analyzed in two steps to isolate the effect of separate components of the seasonal profile:

- The first step will observe the change in costs for unused units when peak demand and average demand stay the same. Only the winter consumption profile will be changed.

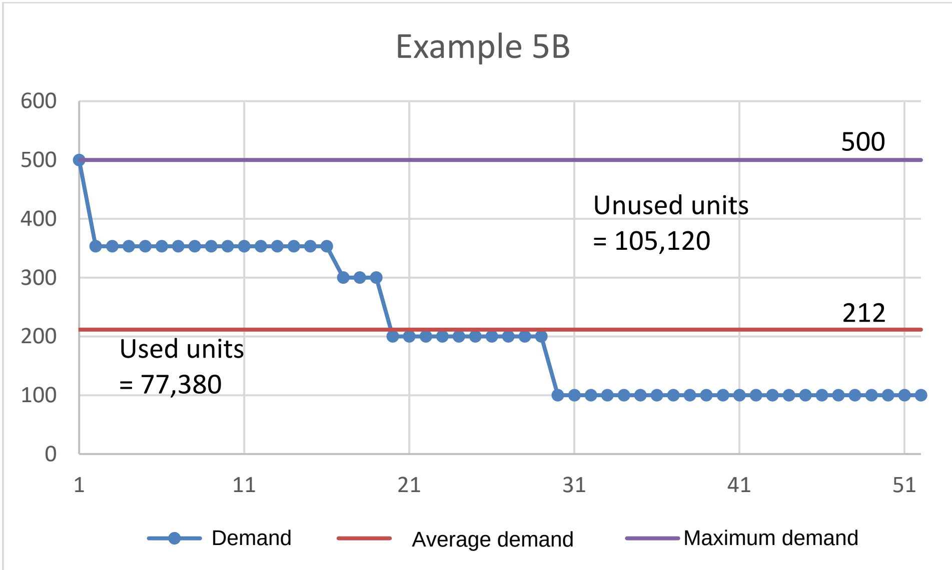
- The second step will observe the change in costs for unused units when the difference between peak demand and average demand changes. In this case, average demand will stay the same, but the winter consumption profile and peak demand will change.

To begin, here are four scenarios in which the consumption profile (real daily consumption) changes, while average demand and peak demand remain the same. To simplify the scale, consumption is ordered from the week with highest real consumption to the week with lowest real consumption. The x-axis is therefore divided into weeks, rather than days, unlike the previous graphs.

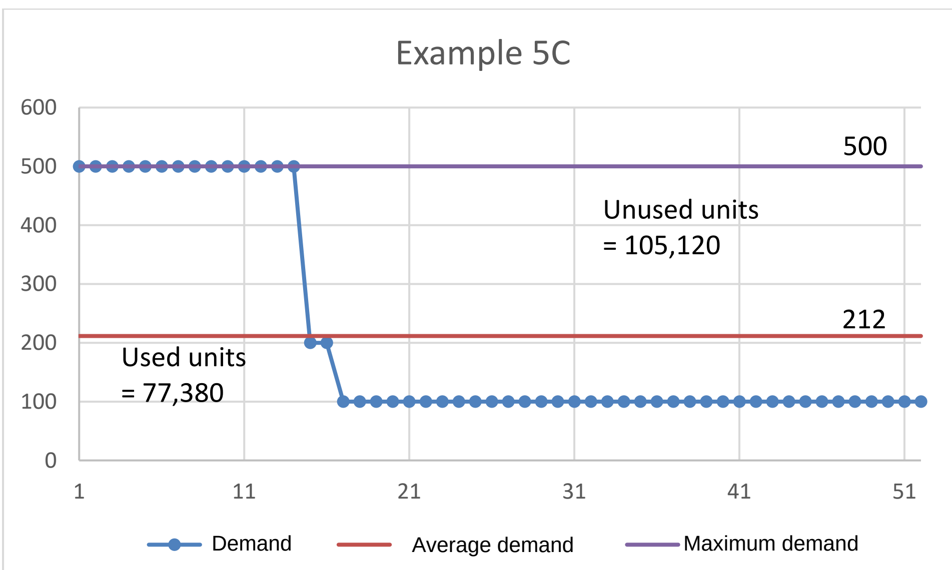
Graph 9



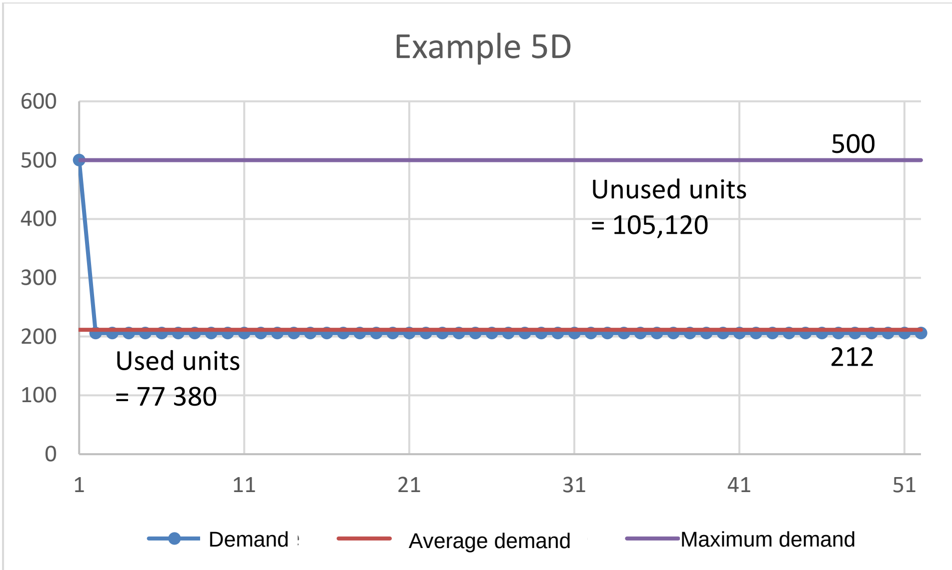
Graph 10



Graph 11



Graph 12

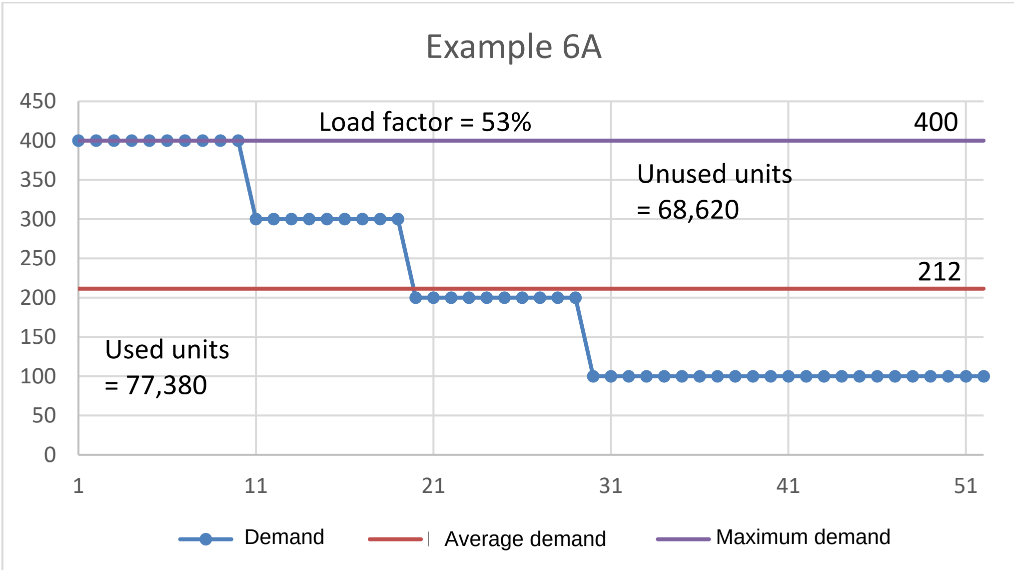


In these four scenarios, despite the different consumption profiles, the customers each consume a total of 77,380 units in the year, or 212 units per day, and they have a peak of 500 units per day. Still working with a supply cost of $1/unit, the total cost of transporting the supply of all these customers in franchise is the same: $182,500 ($500\ units \times 365\ days \times 1\ \$$). The total cost of the units used, in each case, is $77,380. The cost of the unused units is $105,120 ($182\,500 - 77\,380$). These customers all have the same LF: 42.4% ($212 \div 500$). The cost of serving the customers in these four scenarios is the same despite the fact that they consume different quantities every day.

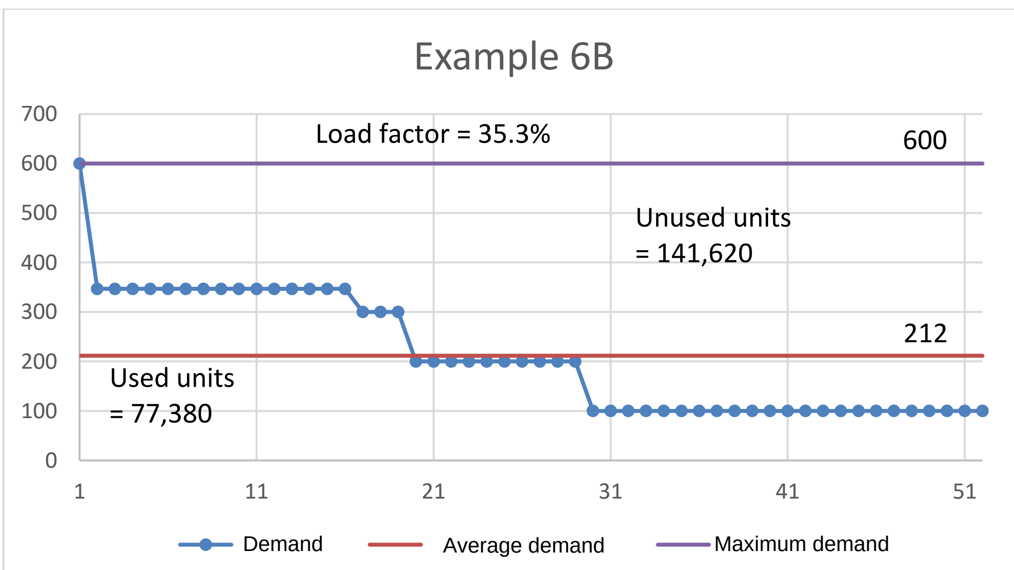
The difference between the peak demand and the average demand therefore allows us to calculate the customer's unused units, no matter what their daily consumption profile is. Furthermore, two different customers who have the same annual consumption and LF automatically generate the same number of used and unused units.

What happens when the peak need is different? Here are four other scenarios in which the average demand remains constant but the peak and daily demand change:

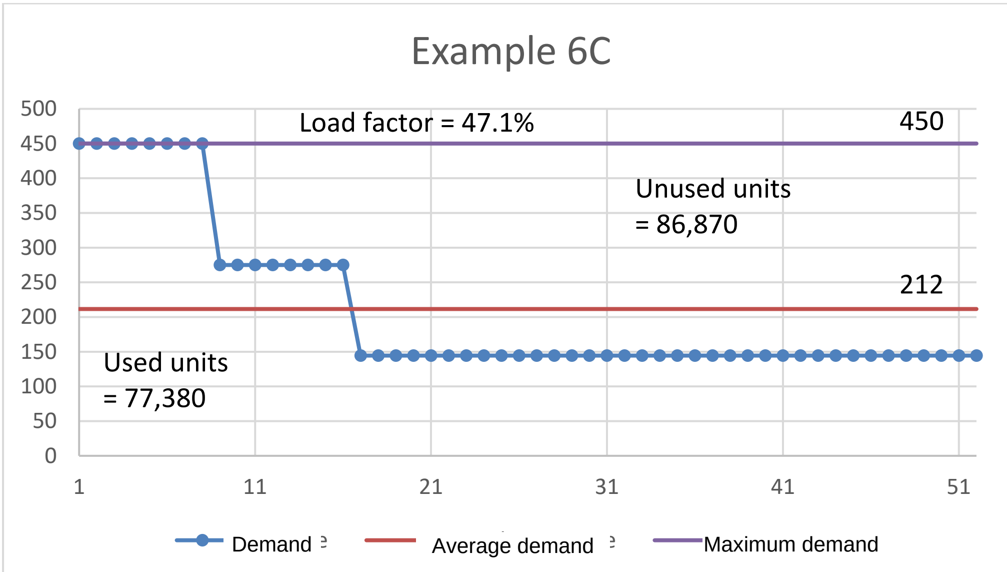
Graph 13



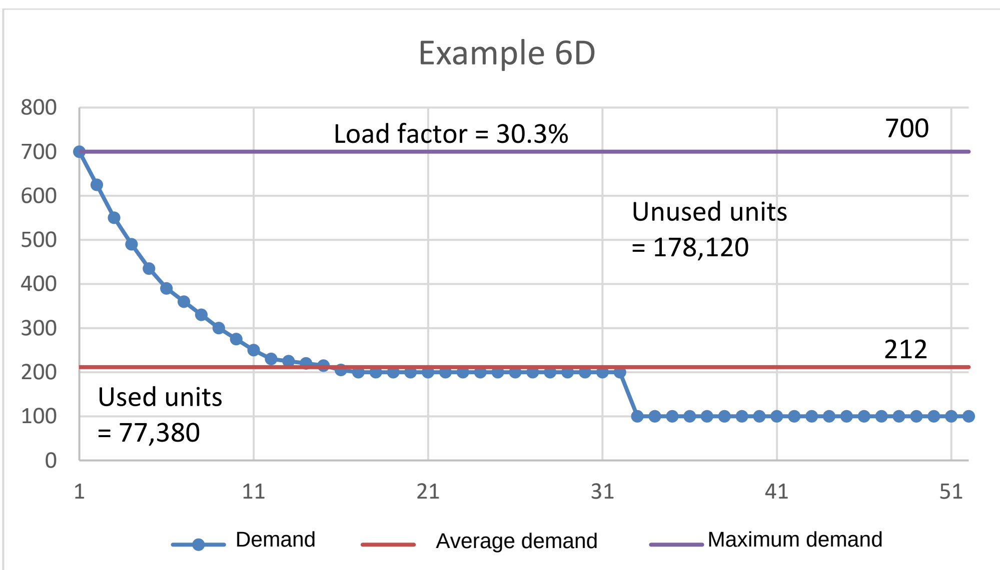
Graph 14



Graph 15



Graph 16



Once again, in all these scenarios, all the customers have the same annual consumption of 77,380 units, but their daily profile and peak demand differ. We can see that the bigger the difference between peak demand and average demand, the greater the number of unused units. In example 6D (Graph 16), the average daily difference is 488 units $(700 - 212)$, which generates the highest total number of unused units, at 178,120. At the price of $1/unit, the excess over the average in this case produces the greatest extra costs: $178,120. This also reflects the lowest LF in all the scenarios, at 30.3% $(212 \div 700)$.

The costs related to the seasonal consumption profile therefore change based on the difference between average demand and peak demand. Consequently, the lower the LF, the higher the cost. Table 1 sums up the differences in the four scenarios presented.

Table 1

Scenario	Load factor *(%)*	Unused units	Actual cost *($)*
	(1)	(2)	(3)
6D	30.3	178,120	178,120
6B	35.3	141,620	141,620
6C	47.1	86,870	86,870
6A	53.0	68,620	68,620
Total	**39.4**	**475,230**	**475,230**

The cost of the unused units does not change linearly with the LF. Since the LF is a relative measure based on the customer's average demand and maximum demand, and since the unused units increase based on the decrease in the LF, the relationship can be shown mathematically. The number of unused units in relation to used units changes inversely to the LF. This function can be shown as: $\frac{1}{LF} - 1$. Knowing the cost to distribute based on the seasonal consumption profile, and using this formula, it is possible to calculate the exact per-unit cost for each customer.

Table 2

Scenario	Load factor *(%)*		Cost per unused unit *($)*	Unit cost per customer *($)*
	(1)	(2)	(3)	
6D	30.3	2,3019	1.00	2,3019
6B	35.3	1,8302	1.00	1,8302
6C	47.1	1,1226	1.00	1,1226
6A	53.0	0,8868	1.00	0,8868
Total	**39.4**	**1,5354**	**1.00**	**1,5354**

In this case, the cost per unused unit is set at $1 (column 3). The customer's per-unit cost (column 4) is therefore equal to the answer to the equation $\frac{1}{LF} - 1$. The cost per unused unit may change annually, however, which would give a different per-unit cost in column 4 than the answer to the equation in column 2.

The per-unit cost established is then used to accurately calculate the cost of the unused units for each customer.

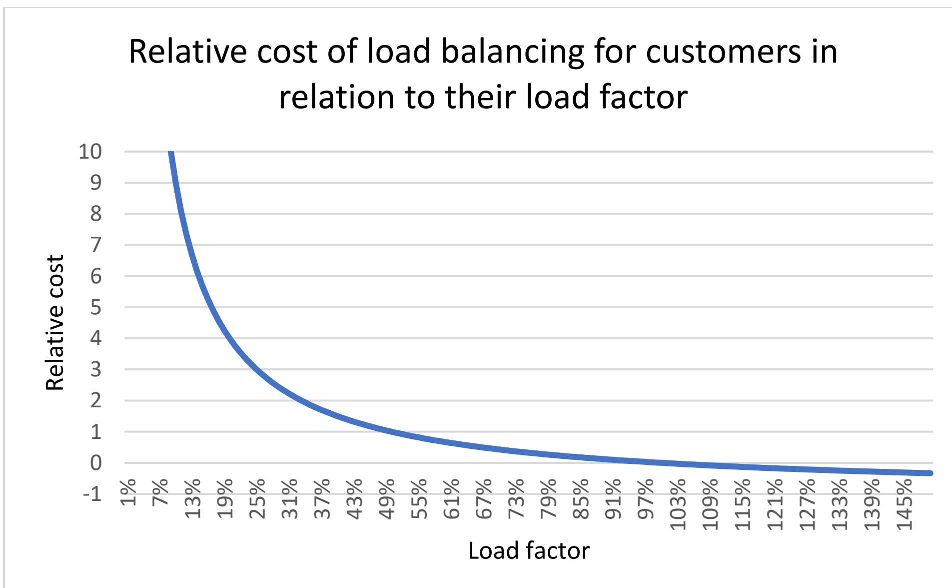
Table 3

Scenario	Load factor *(%)*	Cost per customer *($)*	Units consumed	LF formula estimated cost *($)*	Actual cost *($)*	Difference *($)*
	(1)	(2)	(3)	(4) = (2) x (3)	(5)	(6) = (5) - (4)
6D	30.3	2.3019	77,380	178,120	178,120	0
6B	35.3	1.8302	77,380	141,620	141,620	0
6C	47.1	1.1226	77,380	86,870	86,870	0
6A	53.0	0.8868	77,380	68,620	68,620	0
Total	**39.4**	**1.5354**	**309,520**	**475,230**	**475,230**	**0**

The cost causation to distribute based on the seasonal consumption profile is therefore closely connected to the customers' LF. This relationship is inversely proportionate and allows the costs to be distributed accurately, based on the units consumed by the customer. The customer's daily consumption profile has no influence on the number of used and unused units when the average and maximum demand are constant.

The costs over those established to meet stable demand are therefore caused by all customers with a LF lower than 100%. The lower the LF, the more the cost per unit consumed increases exponentially, as shown in the graph below. For example, a LF of 50% will result in a cost of 1 ($1 \div 0{,}5 - 1 = 1$), whereas a LF of 75% gives a cost of just one-third of that ($1 \div 0{,}75 - 1 = 0{,}33$).

Graph 17

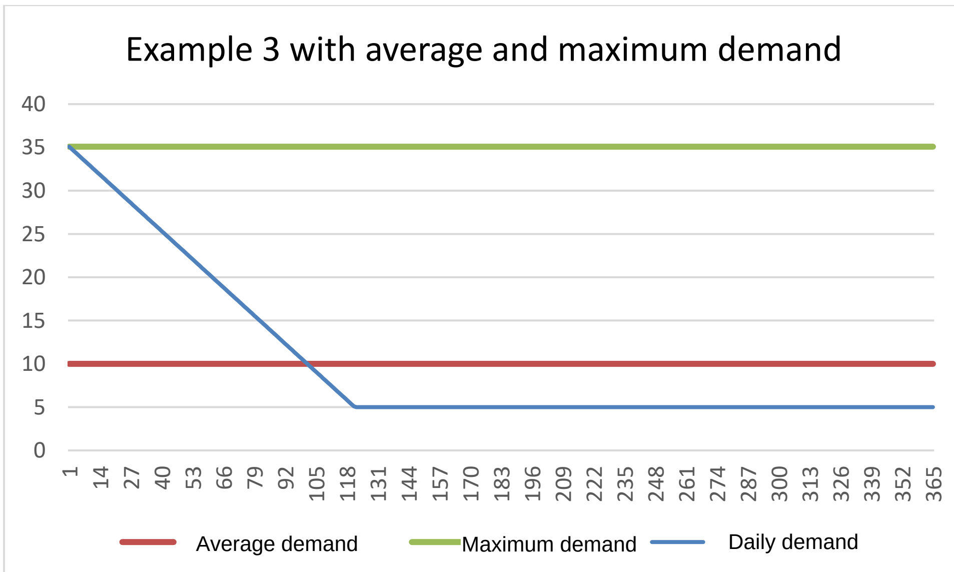


2.1.4. Optimization of transportation costs

Until now in this demonstration, the cost causation has been analyzed on the assumption that the only natural gas supply tool available was TCPL transportation. In fact, the distributor can replace or reduce the transportation tools by storing in franchise or transferring continuous service demand to interruptible service.

First, let us determine in greater detail how the distributor can reduce total transportation costs. To this end, example 3 will be used again, with the addition of average and maximum demand.

Graph 18



In its simplest form, this customer will purchase 35 transportation units per day for a period of 365 days. The customer can then deliver the natural gas it needs, no matter when or how many times its maximum demand occurs. Although it only needs 10 transportation units per day to meet its annual consumption of 3,650 units, it will have at its disposal an annual total of 12,775 units (35×365).

To reduce its total cost, this customer can transform a portion of its continuous demand into interruptible demand. It could, for example, acquired a back-up energy source. For its peak need, this back-up energy source will allow for a direct reduction of the required transportation tools. If the back-up energy source can replace two units on peak days, then the customer can reduce its transportation purchase to 33 units per day ($35 - 2$).

The evaluation cannot end at this step, however. The back-up energy source, in this case, must also cover the need for days on which consumption will be higher than 33 units. To evaluate what the back-up energy source must cover, this customer must first evaluate its maximum need per day.

Table 4

Days	Max. demand
1	35
2	34.75
3	34.5
4	34.25
5	34
6	33.75
7	33.5
8	33.25
9	33
10	32.75

For eight days, every year, the customer's daily demand will be potentially higher than 33 units. The energy source will have to cover the excess over 33 units for each of these days. The total excess to cover can be calculated by comparing the maximum demand before and after adjustment for the alternative energy source.

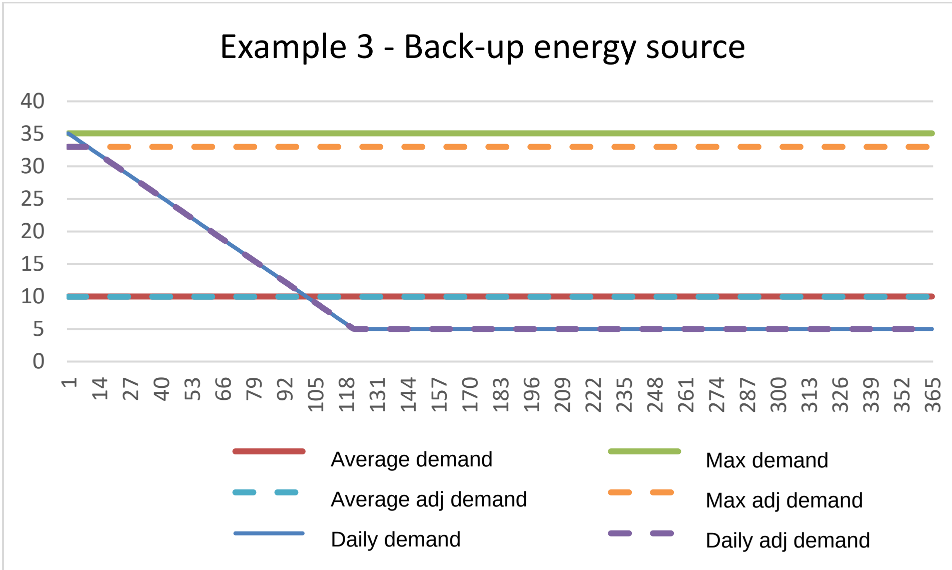
Table 5

Days	Max. demand	Max. adjusted demand	Differential	Cumulative difference
	(1)	(2)		(4)
1	35	33	2	2
2	34.75	33	1.75	3.75
3	34.5	33	1.5	5.25
4	34.25	33	1.25	6.5
5	34	33	1	7.5
6	33.75	33	0.75	8.25
7	33.5	33	0.5	8.75
8	33.25	33	0.25	9
9	33	33	0	9
10	32.75	32.75	0	9

In total, although the back-up energy source only has to cover 2 units on the peak days, it must be able to be used during the winter for up to 8 days and cover a minimum of 9 units. If the back-up energy source cannot cover this minimum, then the transportation tool purchase cannot be reduced by 2 units. For example, if the back-up energy source could only be used for a maximum of 5 days, then the transportation tools could only be reduced by 1.25 units at most (35 – 33.75). Also, if the back-up energy source could only cover a total of 7.5 units for the entire winter, then in this case the transportation tools could only be reduced by 1 unit a day (35 – 34, demand on the fifth day, which requires a capacity of 7.5 units).

That said, assuming that the back-up energy source can cover a peak need of 2 units and that it has the capacity to cover up to 8 days per year (that is, a capacity of 9 units during the winter), the customer will be able to adjust its natural gas needs.

Graph 19



Adding a back-up energy source will allow the customer to reduce the transportation tool purchase by 2 units. Practically speaking, this means a reduction in total transportation units purchased from 12,775 to 12,045 units (33×365). Since the customer is partly replacing its consumption with another energy source, this also marginally reduces its annual consumption from 3,650 to 3,641 units. The number of unused units then falls by 721, from 9,125 to 8,404 unused units. At a per-unit transportation cost of $1, the potential cost reduction is $721. The net reduction will be equal to $721 less the cost of the back-up energy source. Assuming an annual cost of $500 for the back-up energy source, the saving on the transportation tools is $221. In a sense, the back-up energy source replaces the transportation tool and serves as a lower-cost equivalent.

Now let us assume that the customer wishes to reduce its transportation costs even more. To achieve this, this customer purchases a compressor and a compressed gas tank and installs them on its property. The conduit connecting the tank with the facilities can provide up to 3 units a day. This could allow the customer to reduce the transportation units from

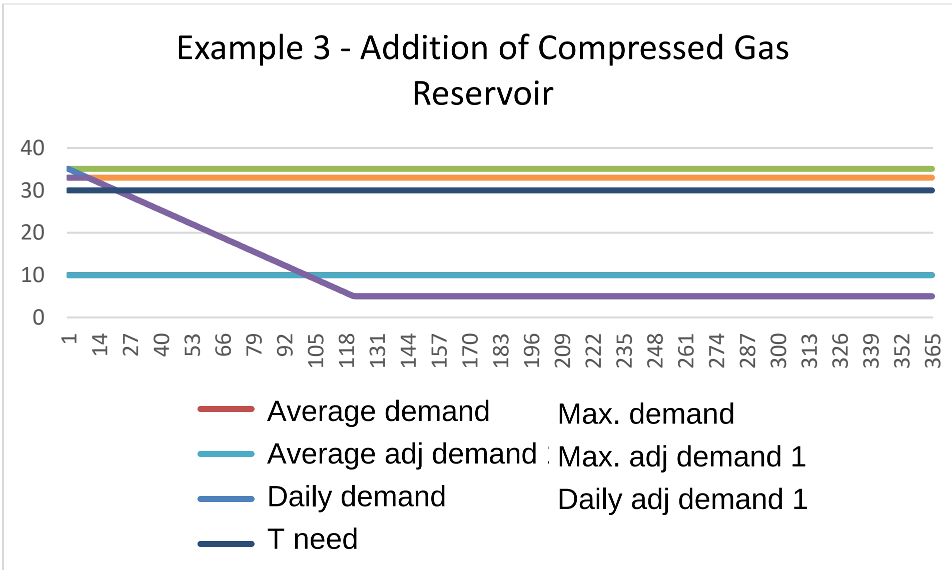
33 to 30 units per day. The customer has to be certain that the tank has the required capacity to compensate for this reduction in peak demand.

Table 6

Days	Max. adjusted demand 1	Need for transportation	Difference	Cumulative difference
	(1)	(2)		(4)
1	33	30	3	3
2	33	30	3	6
3	33	30	3	9
4	33	30	3	12
5	33	30	3	15
6	33	30	3	18
7	33	30	3	21
8	33	30	3	24
9	33	30	3	27
10	32.75	30	2.75	29.75
11	32.5	30	2.5	32.25
12	32.25	30	2.25	34.5
13	32	30	2	36.5
14	31.75	30	1.75	38.25
15	31.5	30	1.5	39.75
16	31.25	30	1.25	41
17	31	30	1	42
18	30.75	30	0.75	42.75
19	30.5	30	0.5	43.25
20	30.25	30	0.25	43.5
21	30	30	0	43.5

The tank will have to cover up to 20 days to cover the demand between 30 and 33 units per day. Furthermore, the tank will need a minimum capacity of 43.5 units, or it may run out before the 20th day of use. Assuming that the customer can acquire such a tank, its transportation requirements will be changed again.

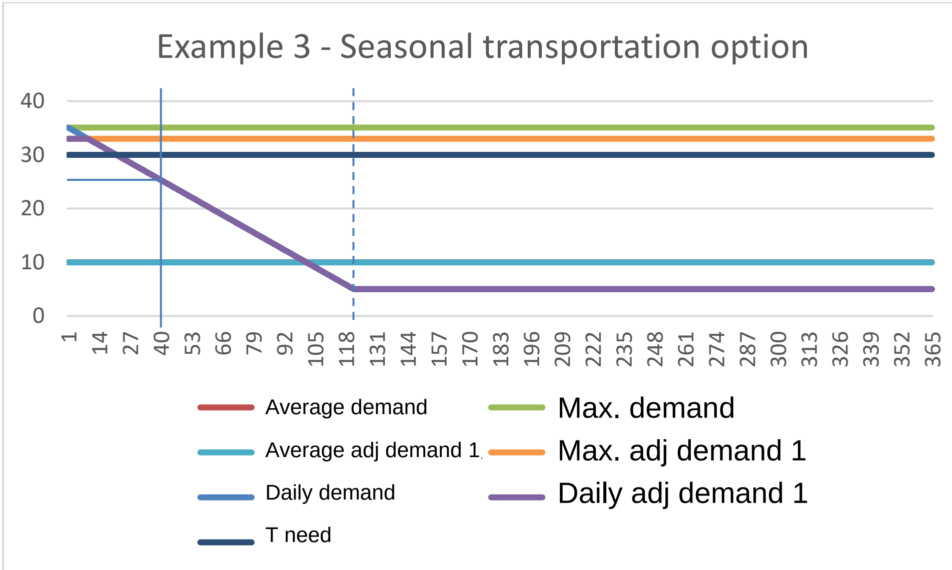
Graph 20



This time, the demands will be the same since there is no transfer to another energy source, but the transportation tool requirement can be reduced to 30 units per day. The potential saving is $1,095 ($3\ units \times 365\ days \times \$1$). If the cost of the tank covering the peak and the capacity is less than $1,095, then the customer can achieve additional savings. Assuming that the annual cost of the tank is $800, then this customer can reduce its cost for unused units by $295. The tank replaces the transportation tool at a lower cost equal to $0.73 per unused unit ($\$800 \div 3\ units\ per\ day \div 365\ days$).

Finally, suppose that the client is offered the chance to purchase 5 units per day of seasonal transportation (covering winter) at a lower cost than the annual transportation cost. This would reduce its annual transportation needs to 25 units per day. Going back to the last graph, we can assess whether this possibility can reduce the customer's annual tool purchase while still meeting its needs.

Graph 21

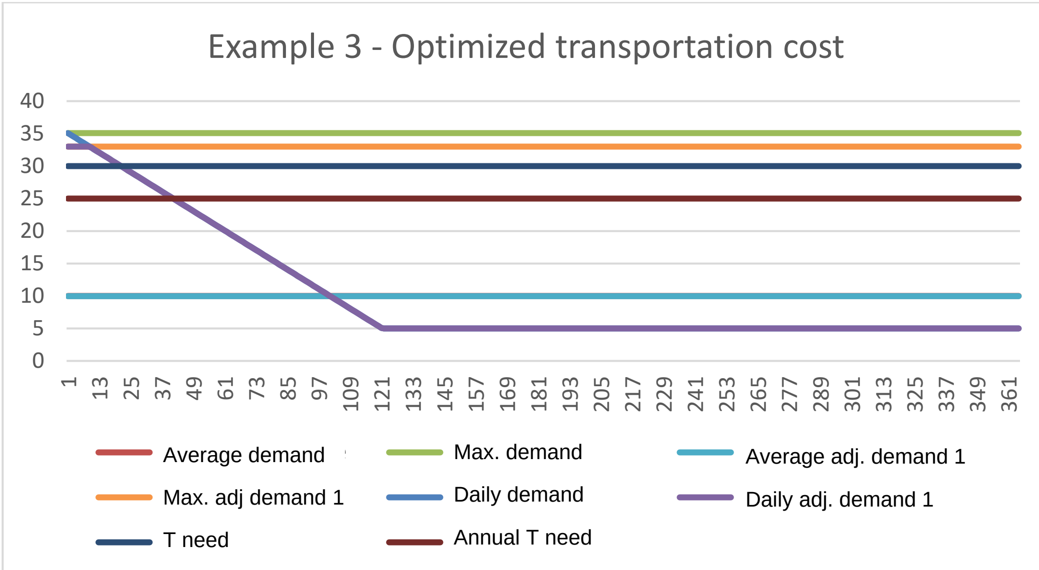


The first vertical line shows that the customer will, according to its own projection, consume 25 or more units a day for a maximum period of 40 days. The second vertical line, dotted, represents all the customer's winter needs. The customer can meet all its needs up to the dotted line using seasonal transportation. Beyond this dotted line, the seasonal tool cannot meet its need.

The customer can therefore reduce its annual purchases thanks to the seasonal transportation offer of 5 units per day, but the price will have to be proportionally lower than the cost of annual transportation. The seasonal transportation tool consists of 150 days of transportation during the winter at a cost of \$2 per unit. The cost in comparison to the annual transportation tool is therefore \$0.82 $(150\ days \times \$2\ per\ unit \div 365\ days)$. Since this price is less expensive than that of the annual transportation tool, which costs \$1/unit, the client can acquire it and reduce its transportation costs by \$0.18/unit. This will reduce the cost of its unused units by \$325 per year $(5\ units\ per\ day \times \$0.18 \times 365\ days)$.

By applying all of these measures, the client can optimize its transportation costs by replacing or reducing its annual transportation costs with less costly alternatives. Here is a graph showing all of the optimizations:

Graph 22



To meet its annual need of 3,650 units and its maximum need of 35 units in a day, the customer replaced:

- part of its consumption with a back-up energy source, at a cost of $500;
- part of its annual transportation purchases with storage capacity at its consumption site, at a cost of $800;
- part of its annual transportation purchases with seasonal transportation, at a cost of $1,500;

Initially, its total supply cost was $12,775, of which only $3,650 allowed for complying with its consumption needs (used units). All of the alternatives used by the customer reduced the total supply cost to $11,925 ($25\ units\ per\ day \times \$1 \times 365\ days + \$500 + \$800 + \$1{,}500$). For its real consumption of 3,650 units, this lowers the total per-unit cost from $3.50 to $3.27. Since the cost of its stable demand has stayed the same at $1 per unit, the cost for its seasonal demand decreases from $2.50 to $2.27 per unit, a reduction of about 9% of the cost.

This example shows that all of the optimizations allow for reducing the total transportation costs. Since these optimizations are only possible when there is a seasonal demand, the savings are related to the seasonal consumption profile.

Although this example is for a particular customer and is attributable to that customer, for a distributor, the exercise can be carried out for global demand. Since global demand represents the combined needs of all customers, the savings can also only be related to all customers that consume with a seasonal profile.

Consequently, the cost of storage tools in franchise, interruptible service and seasonal transportation must be allocated directly based on the consumption profile. All costs associated with the replacement tools must also be allocated based on the consumption profile.

Furthermore, since these costs must, in the long term, be lower than the annual transportation costs, this reduces the total costs that these customers have to absorb.

2.1.5. Causation of stranded transportation costs

If part of the demand is seasonal, the distributor has stranded transportation costs, related to unused transportation units. To serve these customers, the distributor has to purchase transportation tools, or their equivalent, to meet the maximum projected demand.

As demonstrated in examples 1 to 6 of this evidence, a seasonal consumption profile generates unused transportation units. The cost causation of the transportation tools allows us to subdivide the costs between the stable equivalent portion and the seasonal portion.

When the unused units are found in the seasonal portion, their cost can be allocated based on the customer's consumption profile. This allocation is appropriate provided the unused units are the result of the seasonal demand.

In addition to seasonal demand, there can be two other causes for unused transportation units:

- Decrease in consumption by a stable customer for which tools have already been purchased.

- Difference between real demand and projected demand.

To clearly illustrate the difference between these three situations that generate stranded costs, here are some examples for each.

Change in seasonal demand related to temperature

Although the stranded cost dynamic (unused units) associated with seasonal consumption has already been explained, it is still useful to review the topic again.

Temperature fluctuation influences seasonal demand, and consequently the number of used versus unused units. The customer's seasonal consumption will be higher in a cold winter and lower in a warm winter. The same applies to the impact on annual consumption. However, since transportation tools are purchased to meet maximum demand, they remain constant regardless of the type of winter. So the number of unused units will be lower in a cold winter season than in a normal one, and greater in a warm winter. The total stranded costs are therefore greatly influenced by temperature.

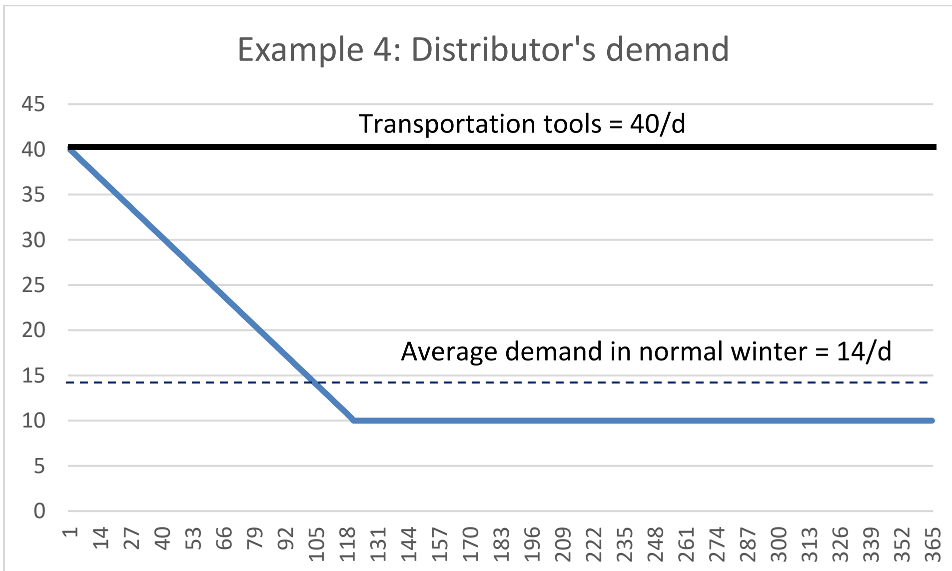
When the cost of the unused units is allocated based on the consumption profile, this dynamic maintains the cost causation: the lower the customer's LF, the more the temperature influences its consumption and the more responsible it is for the change in this type of stranded cost.

As already mentioned, there are reasons other than temperature that can create stranded costs.

Drop in stable portion of consumption

Stranded costs may occur when there is a lasting decrease in the customers' stable consumption. To illustrate, let us go back to example 4, assuming that the customer's demand is actually the distributor's total demand:

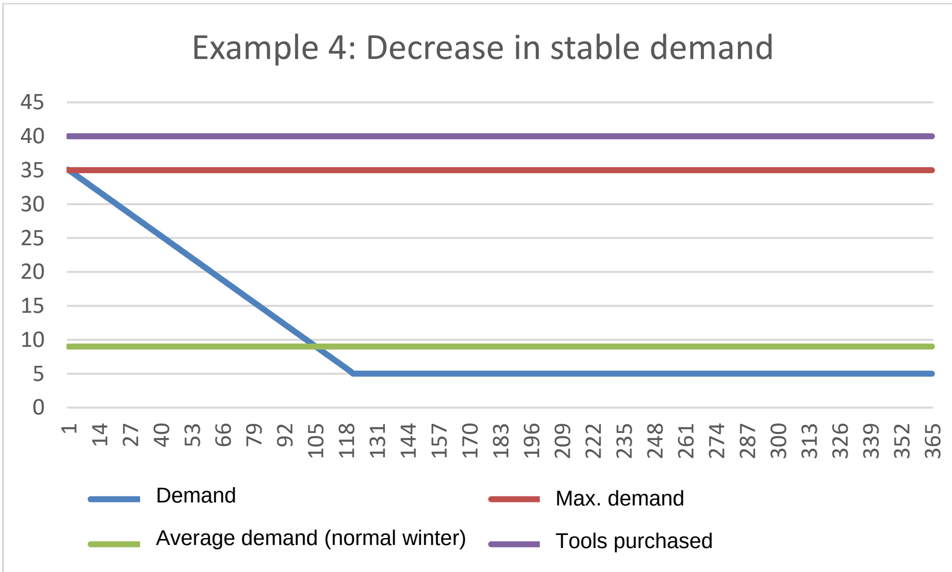
Graph 23



To simplify the explanations, the distributor simply purchases the transportation tools to meet maximum need. The distributor contracts these tools for a two-year period.

Then a major stable customer shuts down in the second year. This customer had a demand of 5 units per day.

Graph 24



The distributor is left with an excess of 5 units per day of transportation, which is added to the stranded costs. For the year, this represents a total of 1,825 unused transportation units. The seasonal profile of the customers is not the cause of these additional stranded costs. In this case, the stranded cost cannot be allocated based on the seasonal consumption profile. The cost was caused because one customer shut down.

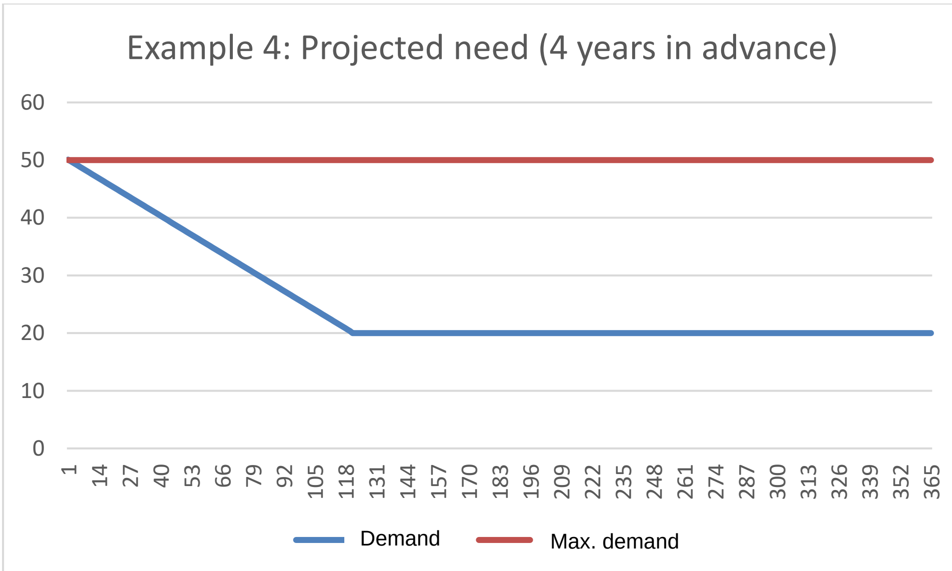
<u>Difference between real demand and projected demand</u>

A change in real demand compared to what was projected can also generate stranded costs.

Generally, distributors have to purchase their transportation tools several years in advance, as the contracts are long-term. To make the purchases, each distributor has to evaluate future demand and establish a progression scenario for probable demand. It is possible, however, that the probable scenario will not occur. This situation can lead to stranded costs over time.

To illustrate this situation using example 4, the projected demand for four years later was generated:

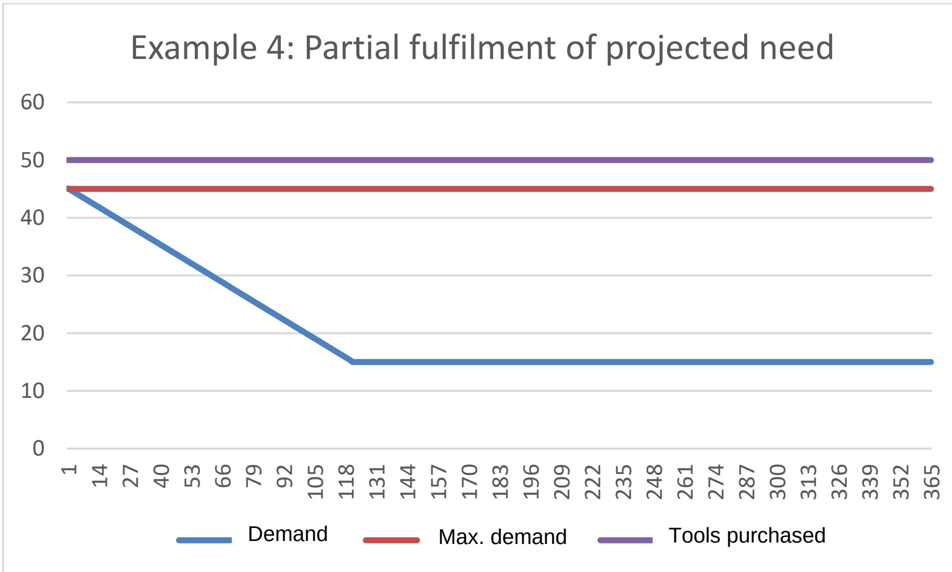
Graph 25



The distributor's scenario projected the connection of stable profile customers totalling 10 additional units per day.

When the year in question arrived, however, stable profile customers totalling only 5 additional units were connected.

Graph 26



The distributor ended up with 5 units' worth of excess transportation tools a day. This represents 1,825 unused units for the year. This time, none of the existing customer caused the stranded costs. The causation of the stranded costs could also be the connection of customers whose intentions were not achieved, a change in the market situation which reduced sales potential between the time of projection and the actual time, or another contextual reason.

Therefore, there may be stranded costs that are not related to temperature, but it may be difficult to establish a clear causal link for these other stranded costs. In the examples presented, isolated situations were analyzed, but in reality, transportation tools are purchased at varying intervals and different times. Furthermore, many customers join and withdraw every year. So how can we assess the costs that are related to the drop in consumption of a particular customer from those related to a gap between real and projected demand in a probable scenario? Since the supply costs take the customers' global demand into account, it is not possible to directly assess stranded costs.

The previous paragraphs show that only stranded costs related to a change in temperature can be allocated based on the seasonal consumption profile. The other stranded costs require specific allocation so they do not penalize a particular type of customer.

2.2. CAUSATION OF SUPPLY COSTS

2.2.1. Different evaluation of transportation

To correctly examine the supply cost causation, the following assumptions have been made:

- There is no constraint on the transportation purchase, i.e. the entire supply purchased can be transported in franchise at any time.
- There is no constraint on the volume that can be purchased each day, as market liquidity allows for considerable volumes to be exchanged at a market price.
- There is no constraint on operational flexibility related to changes in demand over the course of a day.

These assumptions will allow us to evaluate the causal link that is specific to the supply costs alone.

Supply cost causation also has to be evaluated differently from transportation cost causation. Transportation is contracted multi-annually for the same quantity every day of the year. To supply customers with a seasonal profile, the number of transportation units purchased is higher than the number of transportation units consumed (used and unused units). Likewise, the per-unit cost of transportation, under the same contract, is the same throughout the year. Since the transportation market is less flexible, the distributor also has to purchase the capacity required to serve the seasonal customers' peak potential in advance.

In the case of supply, the distributor does not have to purchase excess quantities in advance. The purchases each year are more or less equal to the customers' real consumption. Due to increased demand in winter in Canada and the northern United States, however, the price may vary seasonally, based on inventory and temperature.

Therefore, unlike transportation, the seasonal price increases are not due mainly to unused units (stranded costs) but to the change in the price of the commodity.

2.2.2. Effect of consumption profile

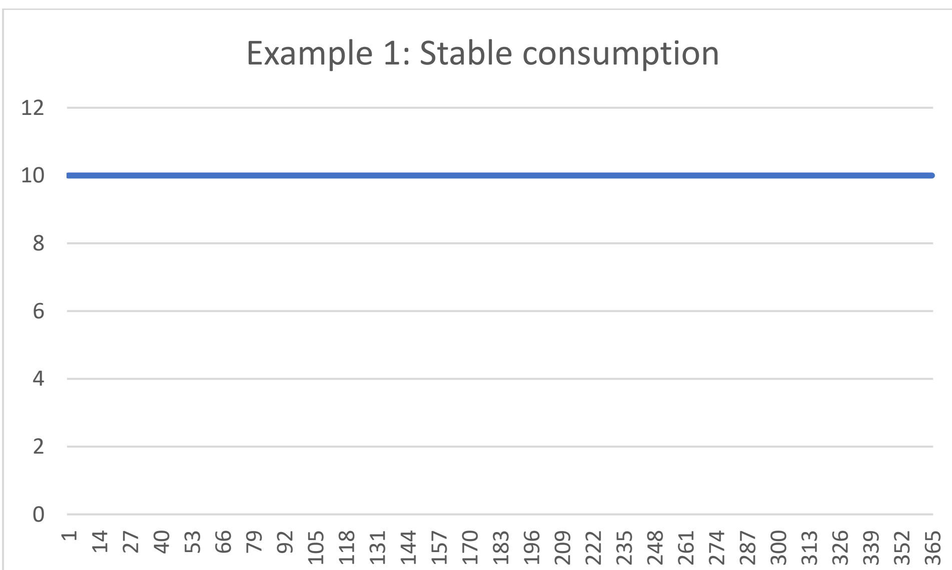
To observe the effect of the consumption profile on the cost of supply purchase, average monthly prices have been set. These prices are presented in Table 7:

Table 7
Price of supply per unit ($)

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Year
4.00	4.00	4.00	4.00	3.00	3.00	3.00	3.00	3.00	3.00	4.00	4.00	3.50

To examine cost causation, let us go back to examples 1 to 4 that we used in the transportation section.

Graph 27

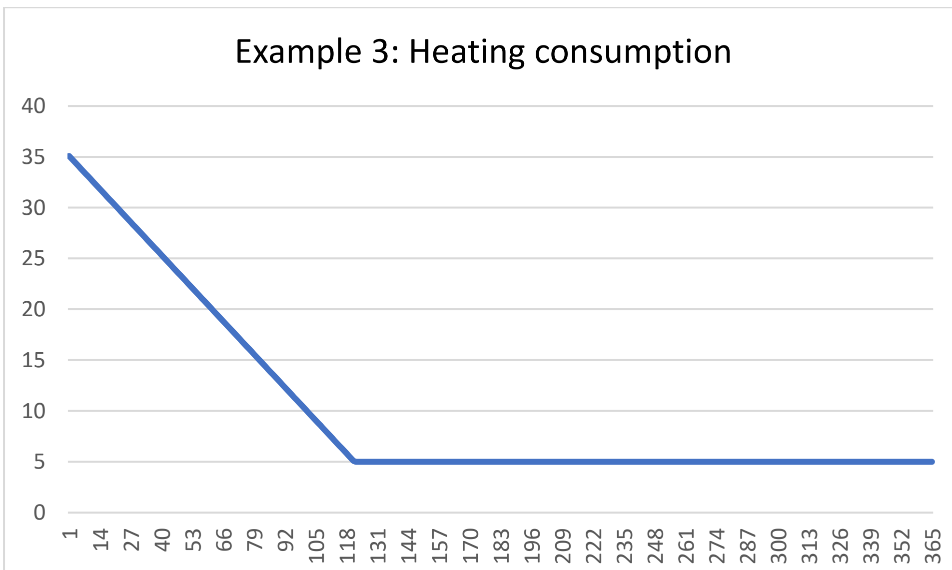


Since the customer has stable consumption, the purchase cost will be equal to the index in each period. With this type of consumption, the customer's average cost is equal to the average annual price of the supply, or \$3.50. The total cost equals the average annual price multiplied by the total consumption. At 10 units consumed per day, the total cost of the supply for this customer will be \$12,775 ($10 \times 365\ days \times \$3.50$).

If this customer doubles its consumption while maintaining a stable profile, its costs will double also. Its average cost will still be equal to the average annual cost, \$3.50. At 20 units consumed per day, the total supply cost will be \$25,550 ($20 \times 365\ days \times \$3.50$).

But what about customers with seasonal consumption?

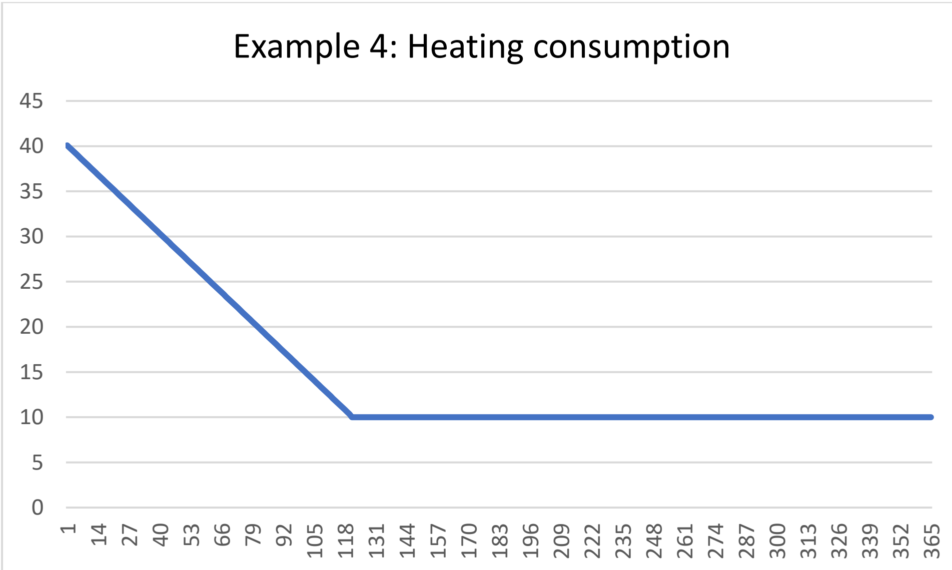
Graph 28



Since all seasonal consumption occurs between November and April (period of the year when prices are at \$4.00, according to Table 7), this customer will purchase more supplies during the winter than during the rest of the year. Of its total consumption of 3,650 units, 920 are consumed from May to October, at a cost of \$3, and 2,730 are consumed from November to April, at a cost of \$4. The customer's total cost will be \$13,680, or an average of \$3.75 per unit consumed.

The cost per unit consumed is therefore different for a customer that consumes seasonally than one that consumes stably. Still using the same prices, what happens when this seasonal customer increases its basic consumption?

Graph 29



The customer will still have to purchase a greater supply during the period from November to April, despite the increase in its stable consumption over the year. Its total consumption is now 5,475 units. For the months from May to October, its consumption has doubled to 1,840. For the months from November to April, the customer has added 905 units and now consumes 3,635 units. The customer's total cost increases to $20,060, but the cost per unit decreases to $3.66. The effect of the price change is lower in comparison to the average price for the year because the customer increased its LF from 28.6% to 37.5%.

Although in this example, the seasonal effect leads to an increased cost for seasonal profile customers, this is not always what happens. Some years the seasonal price may be lower. The factors that explain a lower price in winter may be tied to inventories that are too high or very warm winter temperatures. In the long term, however, the global seasonal effect is likely to be to the disadvantage of seasonal customers.

The supply situation is different from the effect of seasonality on transportation costs. First, unlike transportation, supply purchases are partly periodic, which allows the distributor to avoid excess commitments when the winter is not cold. There are therefore few or no unused supply units. Although seasonality inevitably leads to transportation costs every year, it may lead to costs or savings in terms of supply, depending on how the prices change over the year.

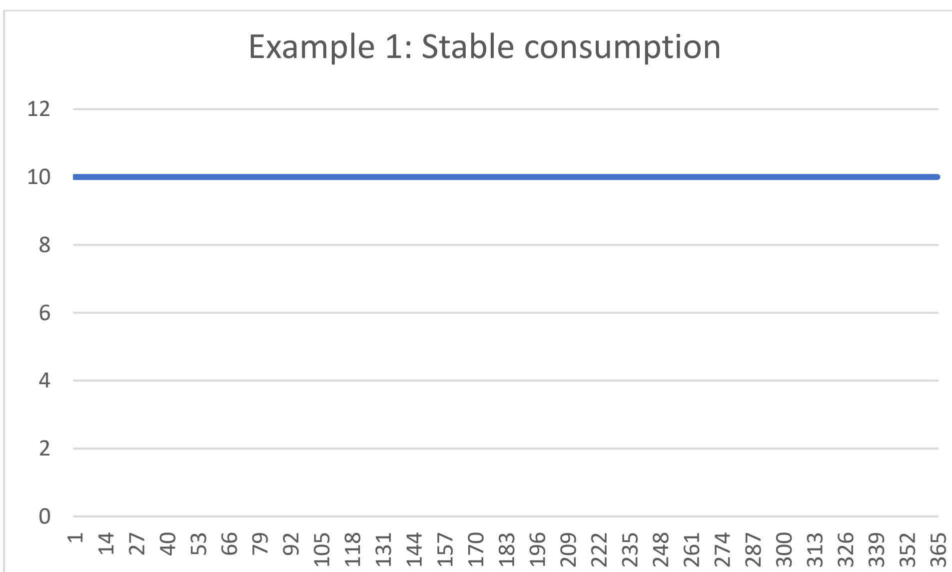
Table 8

Price of supply per unit ($)

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Year
3.00	3.00	3.00	3.00	4.00	4.00	4.00	4.00	4.00	4.00	3.00	3.00	3.50

The annual price would still be $3.50 per unit after inverting the prices.

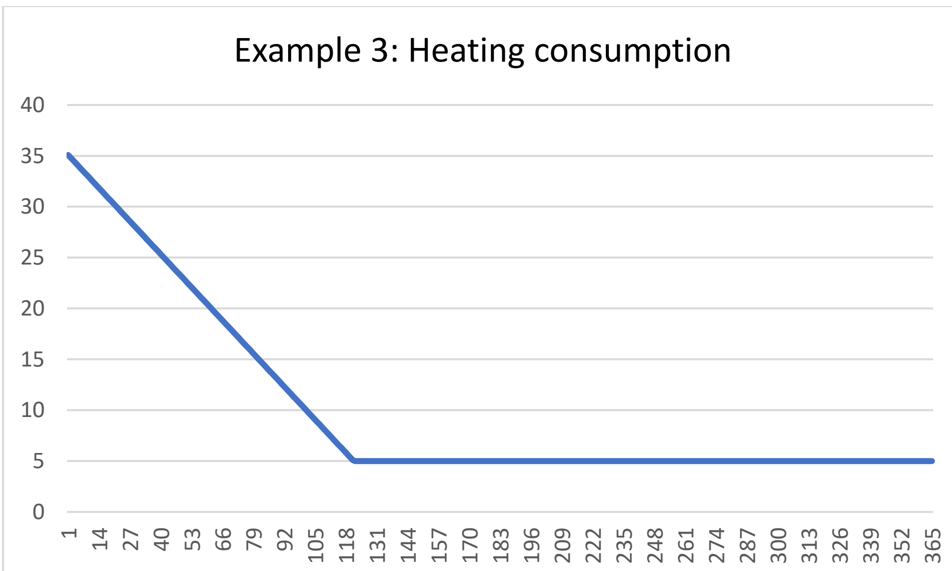
Graph 30



A stable profile customer will maintain the same total price after the prices are inverted, as the average annual per-unit cost will still be $3.50. Therefore, the total cost will still be $12,775 ($10 \times 365\ days \times \$3.50$). By doubling its consumption, its cost will double again to $25,550 ($20 \times 365\ days \times \$3.50$). In both cases, the per-unit cost will still be $3.50, based on the initial prices or the inverted prices.

However, inverting the prices will affect customers with a seasonal profile.

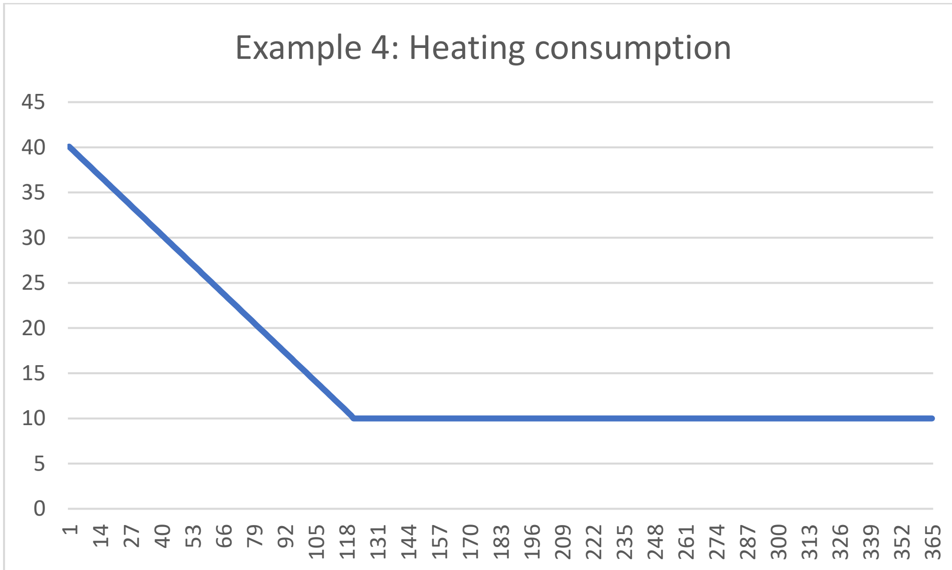
Graph 31



Since all seasonal consumption occurs in the period from November to April (the period of the year when the prices are $3.00, according to Table 8 […]), this customer will have to purchase more supply during the winter than during the rest of the year. Of its total consumption of 3,650 units, 920 units will be consumed from May to October at a cost of $4, and 2,730 will be consumed from November to April, at a cost of $3. The customer’s total cost will be $11,870, or an average of $3.25 per unit consumed. Once the cost of the supply is inverted, the seasonal customer’s per-unit cost will post an inverted gap compared to the annual per-unit cost.

This example can be confirmed by calculating the cost of the supply for example 4:

Graph 32



In example 4, the customer still has to purchase more supply in the winter, despite the increase in its stable consumption over the year. Its total consumption increases to 5,475 units. For the months from May to October, its consumption has doubled to 1,840. For the months from November to April, the client added 905 units and now consumes 3,635 units. The customer's total cost increases to $18,265, but the cost per unit decreases to $3.34. The effect of the price variation is again inverted in comparison to the first supply price scenario. And this effect is lower than in example 3 because the customer increased its LF from 28.6% to 37.5%.

In conclusion, for profiles that coincide with the seasonal price variation, the cost caused by a seasonal profile customer is different from the cost caused by a stable customer when the prices during the year change from the average annual per-unit price. The greater the seasonal consumption in comparison with the total consumption (the lower the customer's LF), the greater the impact of the change in seasonal price on the customer.

2.2.3. Market or annualized supply price?

To correctly represent the cost causation related to supply, do we have to separate the supply cost for a stable profile and a seasonal profile? Not necessarily, since it depends on the operational and commercial constraints faced by the distributor.

Unlike transportation, which requires firm purchases based on peak demand or extreme winters, supply purchases are adjusted throughout the year to meet the demand profile. This means that the number of units purchased during the year is more or less equal to the number of units consumed during the year.

Consequently, if the distributor priced the supply at the monthly market price, then the seasonal purchase costs would be directly reflected in the annual purchase cost of each customer. In the previous section, based on purchases at market price, the per-unit cost for the stable customer was $3.50, while the per-unit cost for the seasonal customer ranged from $3.25 to $3.75, depending on the supply scenario used and the customer's consumption profile.

However, this rather simplistic billing – fair when a whole year goes by with no entries into or withdrawals from the supply service – is not optimal for two reasons. First, the supply service was unbundled to allow customers to make their supply purchases directly. It is therefore important to evaluate the impact of this unbundling in order to ensure that cost recovery is equivalent for both customers of the distributor's supply service and customers that make their own supply purchases. Second, the distributor may want to mitigate price changes in the course of a year for its customers. Indeed, in a very cold winter, it may be difficult for a consumer to receive a bill that includes a single-month spike in the supply price.

Essentially, the distributor may choose between a supply price that reflects the monthly market price or a supply price based on an annualized price. The choice will influence the way the seasonal effect is handled.

If the distributor chooses a monthly market price for the supply:

- The consumption profile of a customer on the distributor's supply service will automatically be reflected in its monthly purchases. As a result, a customer with a stable profile will consume the same quantity each month, at market price, which will be the same as using an annual cost with no seasonal effect. As for the seasonal profile customer, it would consume more units during certain months of the year. The seasonality of the supply price would therefore be reflected in its total costs at the end of the year.

- To achieve balance among these categories of customers, customers who purchase their natural gas directly would have to deliver it based on their own consumption profile, reflecting their costs based on their profile, whether their profile is stable or seasonal. In the case of customers who deliver their natural gas steadily, that is, based on a stable equivalent profile, the distributor should be able to invoice them for the difference in cost (savings or excess) based on their profile.

If the distributor chooses an annualized price for the supply:

- The consumption profile of customers on the distributor's supply service is important. The supply cost would be set at the uniform annual cost. In the examples in the previous section, that means that no matter whether the real cost generated is $3.25, $3.50 or $3.75, all customers would be allocated a per-unit supply cost equal to the annual per-unit cost of $3.50. The cost differential compared to the $3.50 would then be allocated based on the customer's seasonal consumption profile.
- To balance these categories of customers, customers who purchase their supply directly would have to deliver it based on a uniform delivery profile. As a result, their profile would be equivalent to the stable profile. The distributor would have to sell or store the supply to meet the seasonal consumption profile of these customers, which would generate costs more or less equal to those from the customers in its supply service. As a result, changes in costs related to uniform delivery to customers would be recovered from these customers based on their seasonal consumption profile. If customers who purchase their own natural gas deliver it based on their consumption profile, they should be exempt from the costs generated by the use of an annual per-unit cost, because they are assuming the costs directly.

For Énergir, the cost of the supply is annualized and the customers that purchase their own natural gas must take uniform delivery. The cost allocated to supply is therefore the same for all customers for the year, regardless of their consumption profile.

In conclusion, the choice of supply cost based on a monthly market price or an annualized price changes the allocation that must be made in order for the cost causation to be properly represented in the customer's total cost. Since Énergir has an annualized per-unit cost for the supply, i.e. based on an average annual market cost for a stable profile, and since customers who purchase their own supply directly must deliver it using a uniform profile, the allocation of supply costs must consider the natural gas purchase profile required to meet the seasonal needs of all customers.

2.2.4. Splitting costs based on consumption profile

Since Énergir uses an annualized per-unit cost for the supply and asks its customers who purchase their supply to deliver uniformly, then the costs must be split based on the consumption profile. For the same volume consumed, a customer with a stable consumption pattern, as opposed to a customer with a variable consumption pattern, should not be charged the same. This is why separating the supply purchase cost into a portion equivalent to a stable profile and a portion corresponding to the seasonal profile will enable an adequate cost allocation.

To allocate the supply costs related to the stable profile, the allocated cost must be equal to the average annual cost. This cost can be established simply using the monthly price of the benchmark index.

$$\sum_{i}^{12} Month\ i\ rate\ X\ number\ of\ days\ in\ month\ i \Big/ 365$$

It is the approximate price that a customer with a stable profile could expect to pay for its natural gas purchases. In the examples in the previous sections, this price was $3.50 (Table 7 and Table 8).

Once the cost is allocated to the stable profile, the excess must be allocated based on the seasonal profile. In theory, the perfect breakdown of these costs would consist of allocating them based on the customers' consumption periods. This is how the seasonal supply cost was calculated in examples 3 and 4. This revealed differences of $0.16 or $0.25, based on the variations in the customer's consumption profile. Although this method is accurate, it is not practical in Énergir's particular situation because of the difficulty of measuring the real impact of the variation in consumption by the customer or group of customers.[8] Therefore, we need to find another way to approximate the cost caused by customers with a seasonal profile.

In general, the lower the LF, the greater the difference between the real cost caused by the seasonal profile and the annualized cost. The LF can therefore serve as an approximate basis for allocating the costs of customers with a seasonal consumption profile.

However, using the LF to allocate seasonal supply costs will not be as accurate as for unused transportation units. In the case of transportation, the unused units are allocated using the LF, while for supply, the excess cost over the stable purchase of units are used. Furthermore, the excess transportation costs are always included, as they are purchased in advance. In the case of supply, the excess cost or savings depends on the market context and the severity of winter conditions. In addition, while the transportation capacities are established at the beginning of the year and their cost is fixed and does not change over the year, the supply cost changes every day, based on the offer and demand in the market.

All these differences mean that using the LF for supply cost allocation may differ from the real excess cost that a customer incurs. To demonstrate this, new monthly supply prices are used:

Table 9

Price of supply per unit ($)

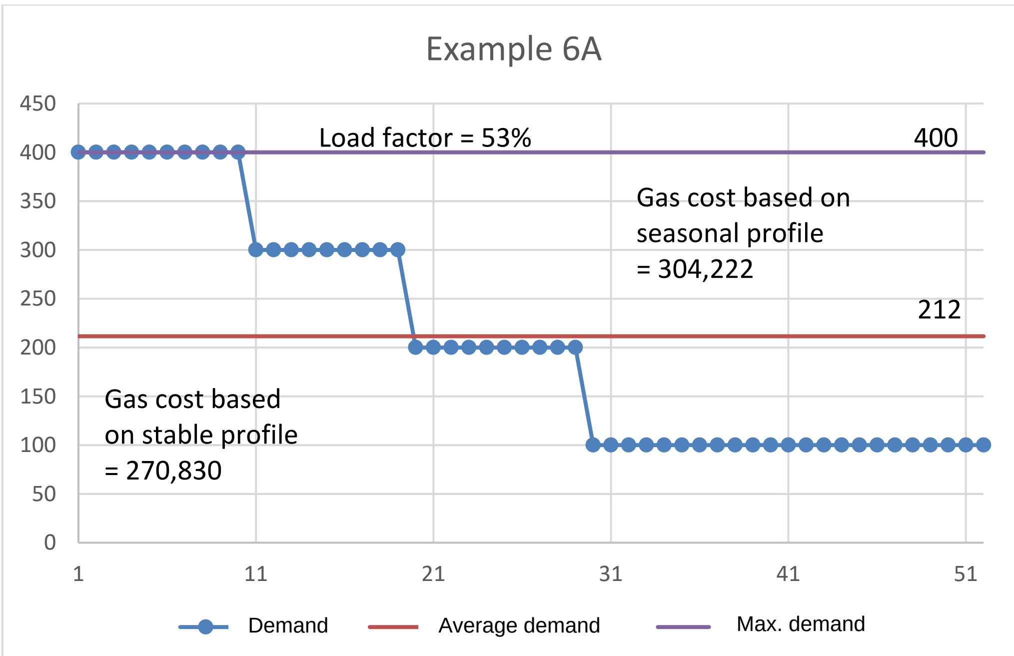
Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Year
5.00	4.00	4.00	3.20	3.20	3.00	3.00	3.00	3.20	3.20	3.20	4.00	3.50

[8] This topic is analyzed in greater detail in Appendix 1.

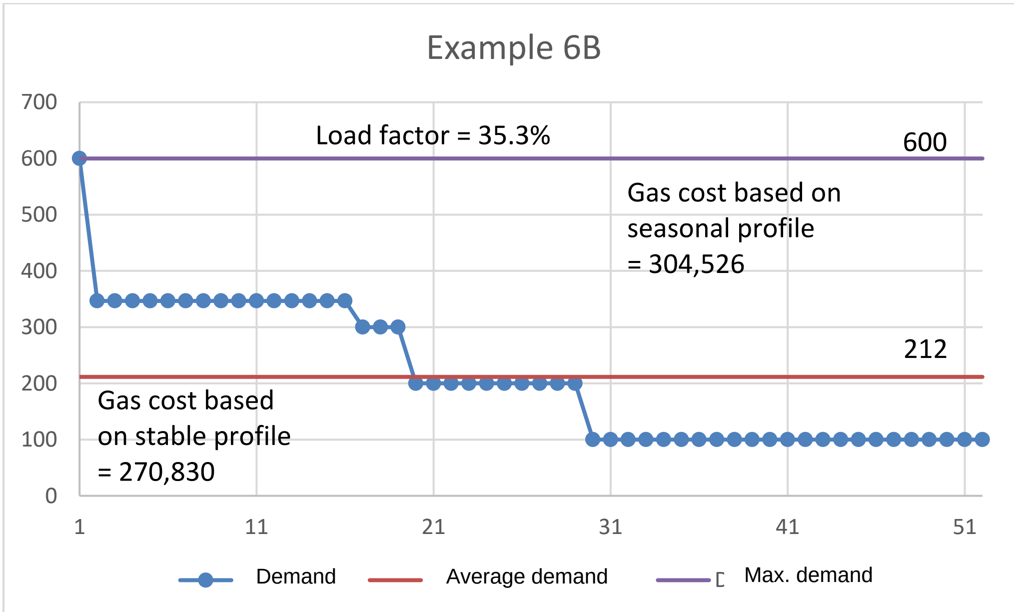
These prices, which are more varied during the winter, will demonstrate the monthly supply price variation and its effect on the cost for a seasonal profile.

Let us return to examples 6A to 6D to calculate the excess supply cost:

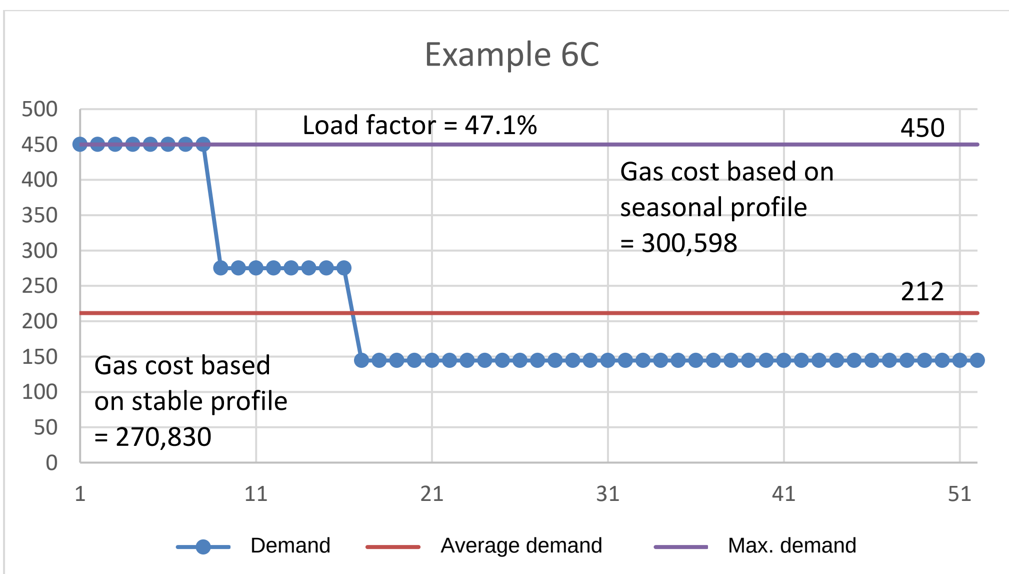
Graph 33



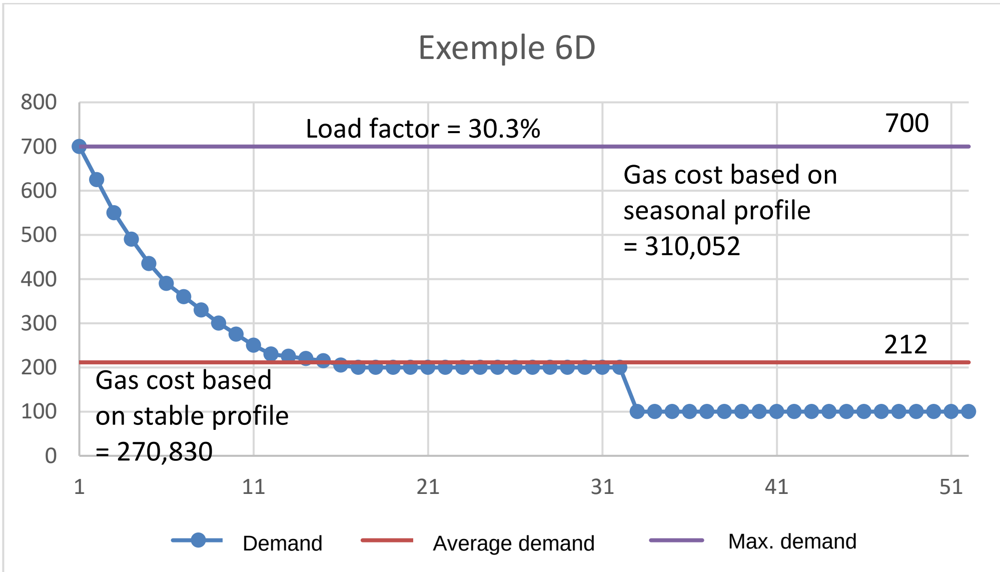
Graph 34



Graph 35



Graph 36



1 Here is a summary table of gaps between the uniform cost and the variable cost, based
2 on profiles:

Table 10

Scenario	**Load factor** *(%)*	**Uniform cost** *($)*	**Actual cost** *($)*	**Difference** *($)*
	(1)	(2)	(3)	
6D	30.3	270,830	310,052	-39,222
6B	35.3	270,830	304,526	-33,696
6C	47.1	270,830	300,598	-29,768
6A	53.0	270,830	304,222	-33,392
Total	**39.4**	**1,083,320**	**1,219,398**	**-136,078**

3 Unlike the situation for transportation, here the cost does not always drop based on
4 a higher LF. The excess supply cost due to the seasonal profile in scenario 6A is almost
5 the same for scenario 6B, despite a LF that is 17.7% higher.

What happens if the highest price occurs during the winter, but not necessarily during the coldest month? Here are some different prices to test this:

Table 11

Supply price per unit

Jan.	Feb.	Mar.	Apr	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Year
4.00	5.00	5.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	4.00	3.50

In this price scenario, the monthly index (consisting of prices from the previous month) is higher in February and March. The daily prices were therefore higher in January and February. We can suppose that inventories dropped significantly from the end of December to the end of January, which resulted in a price increase toward the end of winter.

Table 12

Scenario	Load factor *(%)*	Uniform cost *($)*	Actual cost *($)*	Difference *($)*
	(1)	(2)	(3)	
6D	30.3	270,830	301,174	-30,344
6B	35.3	270,830	307,676	-36,846
6C	47.1	270,830	299,243	-28,413
6A	53.0	270,830	306,357	-35,527
Total	**39.4**	**1,083,320**	**1,214,450**	**-131,130**

Once again, based on this price scenario, the real costs generated by variable profiles no longer follow the increase in the LF.

These results are inconsistent with the results of the tests conducted in section 2.1.3 for transportation, where the seasonal costs followed the changes in the LF. When the customers' consumption profiles change based on factors other than temperature, the LF cannot provide a perfect cost breakdown.

The causation of seasonal supply costs for each customer varies essentially based on two gaps:

- The gap between the monthly volume and the annual average volume
- The gap between the monthly supply price and the annual average supply price

This explains why the use of a consumption factor such as the LF, which is less accurate than the application of a monthly variation in consumption combined with a change in the supply price, cannot accurately allocate the seasonal supply costs for different profiles when they are not related to changes in temperature.

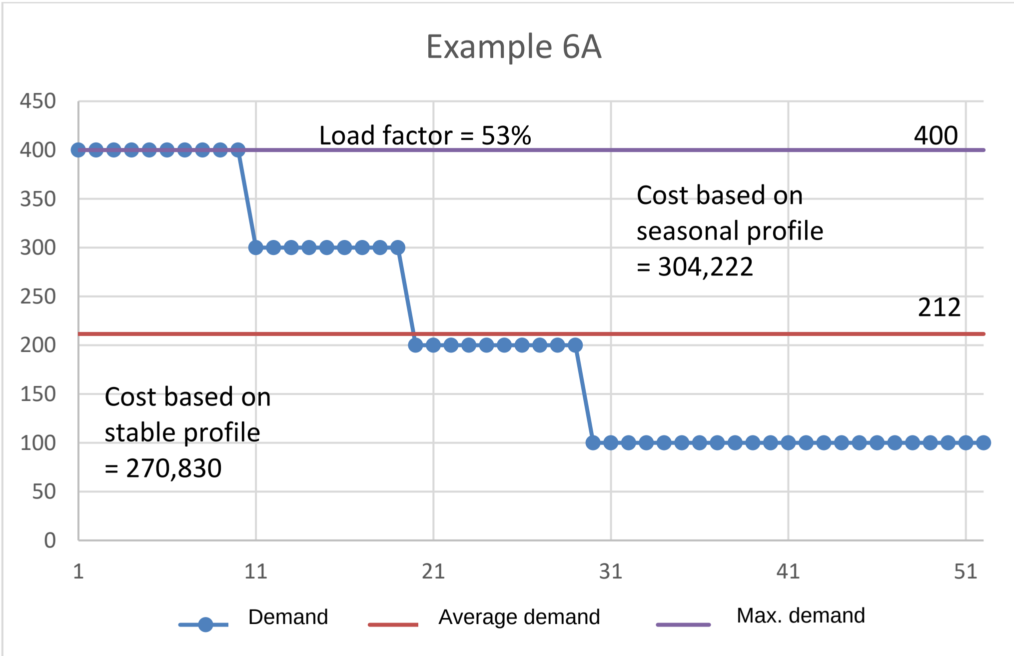
2.2.5. Costs incurred by customers purchasing their own supply

Customers who purchase their own supply cause different costs, based on whether or not they deliver based on a uniform profile.

When the customer delivers based on its exact consumption profile, ("deliver and burn"), it does not cause excess supply costs for the distributor even if its consumption is seasonal.

However, when the customer delivers based on a uniform delivery profile, it causes the same seasonal costs as customers in the distributor's supply service. To explain this, let us return to example 6A from the previous section:

Graph 37



If the customer purchases its own supply, it will deliver 212 units per day throughout the year. At an average annual cost of \$3.50 per unit, its cost will be \$270,830. The distributor will have to provide up to 400 units per day in winter, when the price is higher, and only 100 units per day when the price is lower.

If the distributor does not have any storage capacity, its cost will be \$33,392 $(304\,222 - 270\,830)$. In the months of December, January, February and March, the additional cost between the market price and the average annual price will be absorbed by the distributor. During the summer, the difference between the resale price of the excess supply and the average annual price will also increase the distributor's total cost.

Since direct supply purchase customers generate the same costs for the distributor as customers using its supply service, the causation of these costs is the same for both types of customers.

The next section further supports the analysis of costs generated by non-uniform delivery profiles. It also focuses on and quantifies consumption deviations compared to delivery-related deviations.

2.2.6. Costs incurred by customers that purchase their own supply and do not deliver uniformly

Currently, Énergir anticipates that customers who provide their own delivery service will deliver, on a daily basis, a volume equal to 1/365 of their projected annual consumption to the agreed-upon point; the projected delivery profile is uniform. The mechanism used to account for deviations from a uniform delivery profile is transposition, which is incorporated into the calculation of the individualized load-balancing rate. This was introduced at the same times as rates were unbundled. The mechanism did not previously exist, even though customers already provided their own delivery service and were expected to have a uniform delivery profile. The decision was made to introduce the notion of transposition following the introduction of a customized rate for billing the portion of supply tool costs generated by the customers' consumption profile. This meant that a customer could be exempt from billing for the load-balancing service if it delivered the same volume as it withdrew on a daily basis and limited the possibilities of arbitration if a customer delivered nothing during the winter, for example.

> *"The unbundled rates will have to account for the customer having the option to supply the merchandise according to different delivery profiles, ranging from always delivering the merchandise according to a uniform profile (as is currently the case) to delivering a daily volume equal to its load; this type of customer is known as "deliver and burn."*[9]

Énergir questions the application of transposition, the rules of which are described in article 13.1.4 of the *Conditions of Service and Tariff* for all customers who deliver their supply, independent of their choice of carrier. Énergir first draws a link between the reciprocity of the franchise delivery profile and the consumption profile: For a customer who delivers its supply to the franchise, one less unit delivered during the peak period has the same impact on costs as one more unit withdrawn during the peak period. Second, Énergir checked to see if the impact is the same for a customer that supplies the natural gas it takes from its own facilities but uses Énergir's transportation service and concluded

[9] R-3443-2000, SCGM-2, Document 1, page 7, l. 21.

that it is not. The two delivery profile variants, in franchise and outside franchise, cannot therefore be allocated the same costs if causalities are to be taken into account.

Customers who deliver their supply to the franchise

First, we will analyze the case of supply deliveries made on Énergir's territory (for customers who provide their own transportation and delivery services).

The following example was used:

- Two customers, Customer 1 and Customer 2, who deliver their supply daily to Énergir's territory.
- The customers are required to deliver the same volume as they withdraw during the year. If the customer delivers a volume that differs from the volume withdrawn during a day, it must make up for this difference later in the year, which involves using the load-balancing service.
- Customer 2 is responsible for ensuring that the sum of the volumes delivered is equal to the sum of the volumes withdrawn on a daily basis. It can be seen as representing the customers who use Énergir's transportation and supply services.
- For simplification purposes, we used a year made up of only 12 days to simulate a fictitious year.

[…] Table 13 presents the price of the supply components for this example.

Table 13

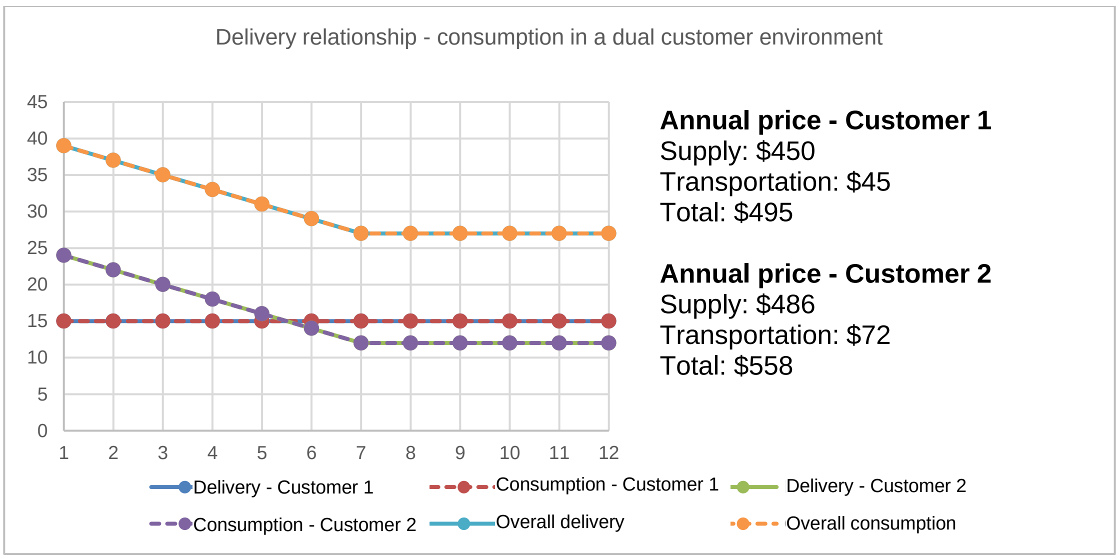
Supply	**Day 1 to Day 6**	**Day 7 to Day 12**
Variable premium	$3.00/unit	$2.00/unit
Transport	**Day 1 to Day 12**	
Fixed premium	$3.00/peak unit	

The annual transportation price is equal to the maximum volume delivered multiplied by the price of $3.00/peak unit. For a maximum delivery of 15 units, the cost is $45 ($3/unit x 15 units).

Finally, the annual price paid by each customer is evaluated for each example. The price is calculated based on the tools acquired by the customer prior to the cost sharing. For example, when Customer 2 delivers more supply to the franchise to meet the daily demand from Customer 1, the additional costs incurred are not reflected in the amounts paid to the suppliers by Customer 1, which are displayed on the graph.

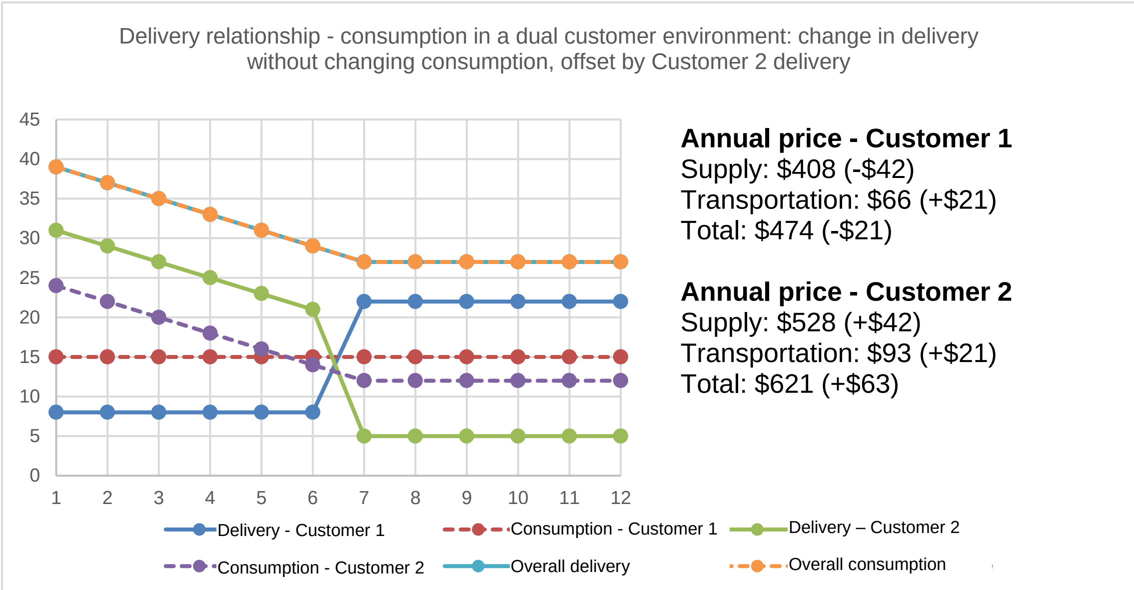
Graph 38 illustrates a situation in which both customers deliver the volume that they withdraw each day (the curves are superimposed on the graph).

Graph 38



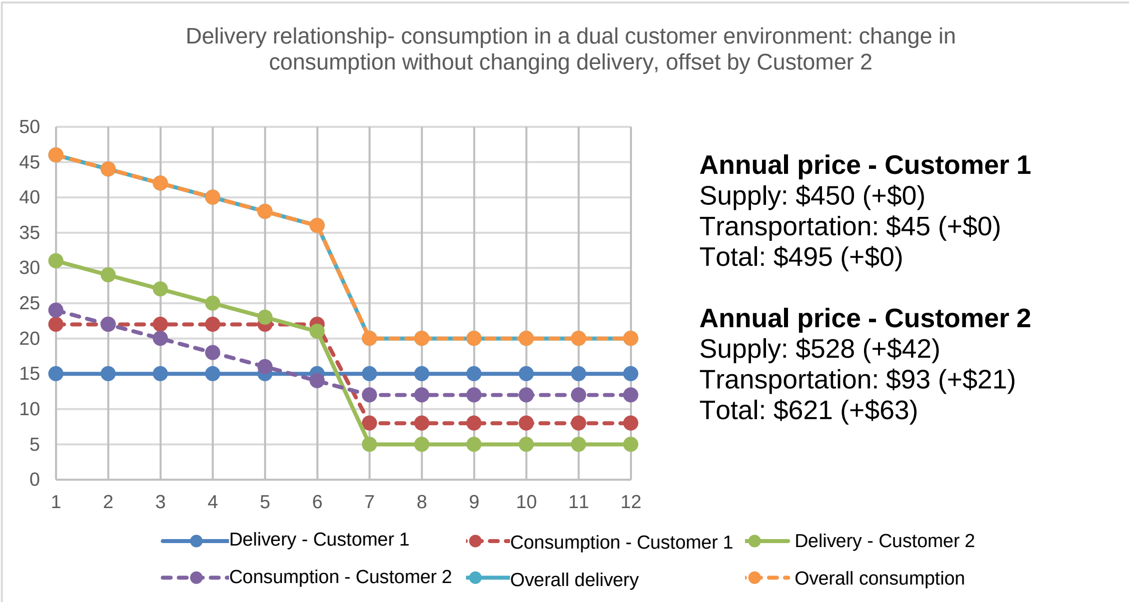
The cost incurred by Customer 1 when it deviates from the uniform delivery profile, while maintaining a uniform consumption profile, is shown in Graph 39. Because Customer 1 delivers seven fewer units during the first six days and seven extra units during the last six days, Customer 2 adjusts its daily deliveries so that the overall daily delivery to the franchise corresponds to the overall daily consumption.

Graph 39



If Customer 1 changes its withdrawals, Customer 2 also adjusts its daily deliveries by maintaining a uniform delivery profile, as illustrated in Graph 40. The additional costs generated by Customer 1 compared to the baseline scenario (Graph 38) are therefore assumed by Customer 2. They are the same in Graph 39 and Graph 40 ($63). Moreover, the impact of Customer 1’s non-uniform delivery profiles on Customer 2’s costs is the same per service (+$42 and +$21 for the supply and transportation services, respectively).

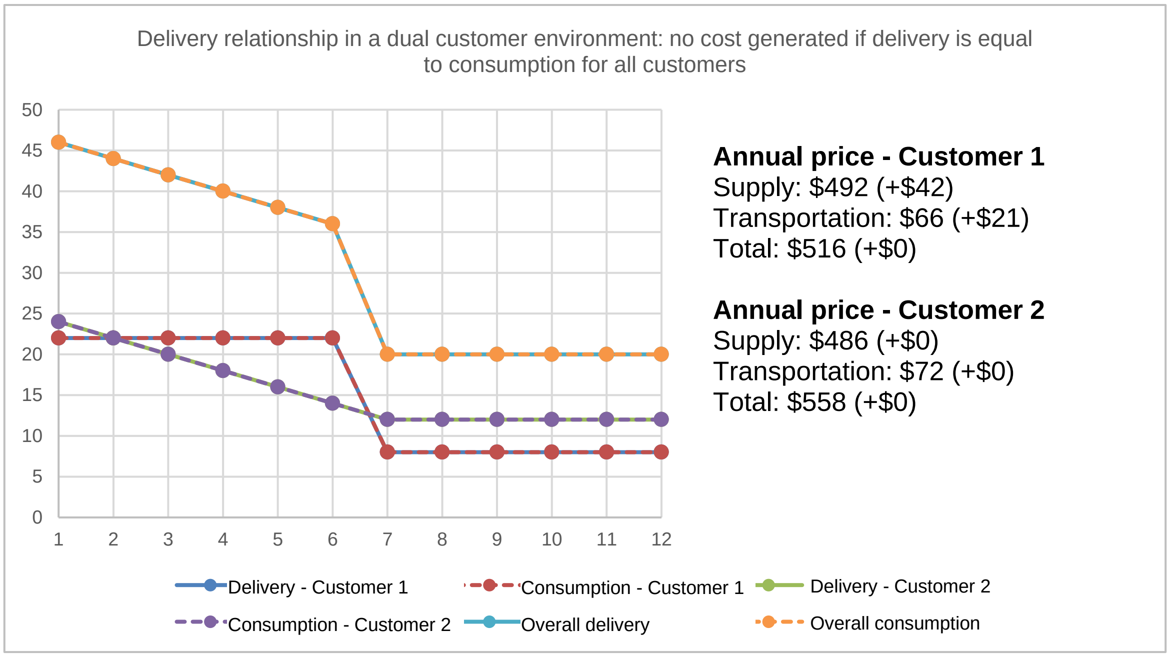
Graph 40



In reality, Customer 2 represents all customers of Énergir's supply and transportation services, and Customer 1 represents customers who provide their own supply services. This theoretical example illustrates the motivation behind the transposition of volumes: When it comes to the costs of customers who use Énergir's transportation and supply services, one less unit delivered has the same impact as one extra unit withdrawn (when the delivery is made to the franchise). Therefore, when the load-balancing rate was developed in order to create customized bills based on the customer's consumption profile, there was justification for billing the delivery profile and the consumption profile together. As such, Customer 1 may have a customized load-balancing price of zero if it delivers exactly the same volumes as it withdraws, because it generates no costs for Customer 2.

In Graph 41, we note that the cost of supplying Customer 2's demand is the same, with or without Customer 1 when the latter delivers the same volume as it withdraws. The same reasoning applies in Graph 38.

Graph 41

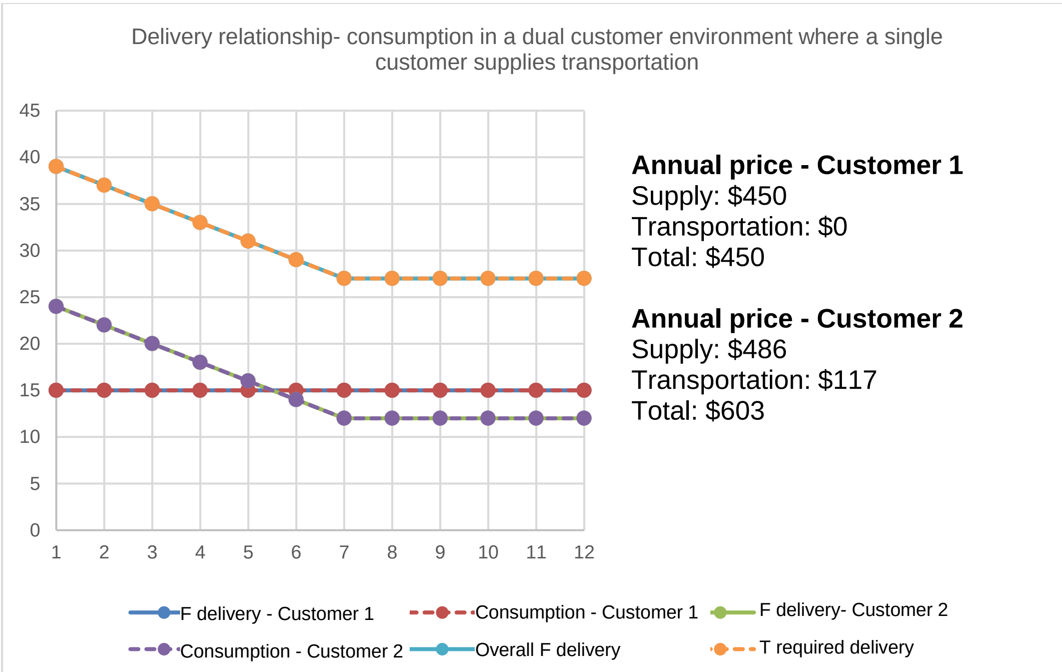


<u>Customers who deliver supply to a reference point outside of Québec</u>

Let us go back to the last example to demonstrate that the effect on costs of a non-uniform delivery profile is not the same in this case as the effect of a non-uniform consumption profile. This difference stems from the fact that Énergir does not have to adjust the use of its transportation capacities in this case, unlike the situation in the previous section, in which customers delivered the supply directly to the franchise. As a result, only costs associated with the seasonal nature of supply prices are generated when a customer using its own supply service makes non-uniform deliveries.

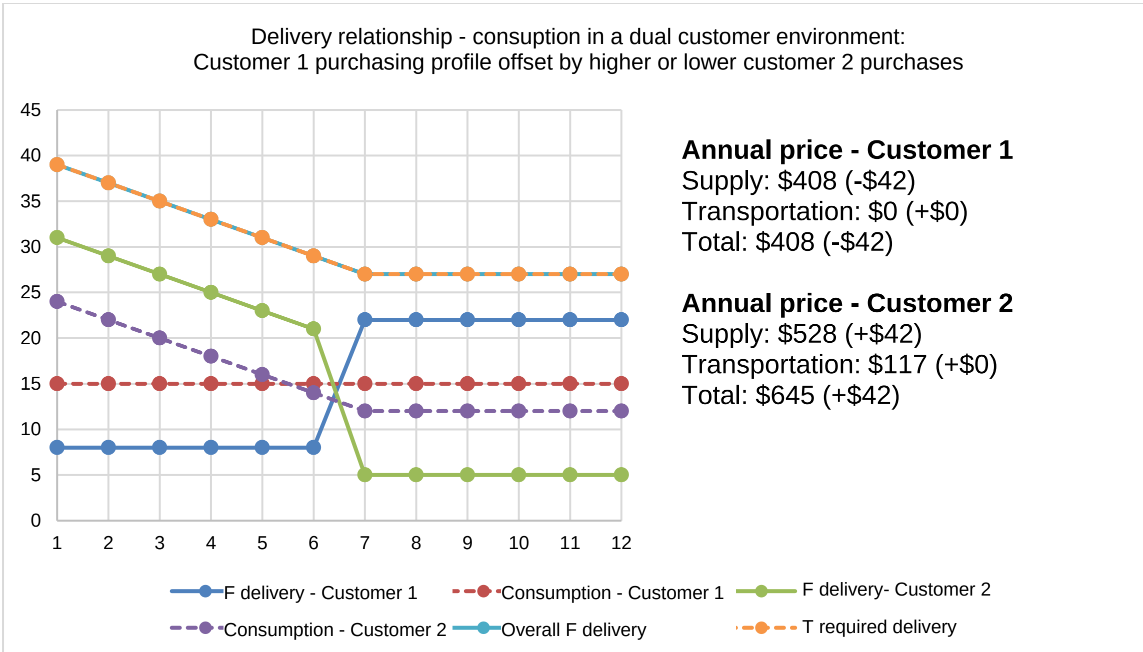
In the example below, rather than each customer providing its own transportation service, Customer 2 (who represents customers using supply services contracted by Énergir) is responsible for transporting the entire supply to Énergir's territory in order to meet the daily demand. The same prices are used in the previous example (see Table […] 13).

Graph 42



If Customer 1 does not deliver exactly the same volume as it withdraws, as shown in Graph […] 43, it generates costs for Customer 2. These costs are only generated by the acquisition of supply: Customer 2 must purchase more or less supply if Customer 1 delivers more or less than it withdraws to a reference point outside of Québec.

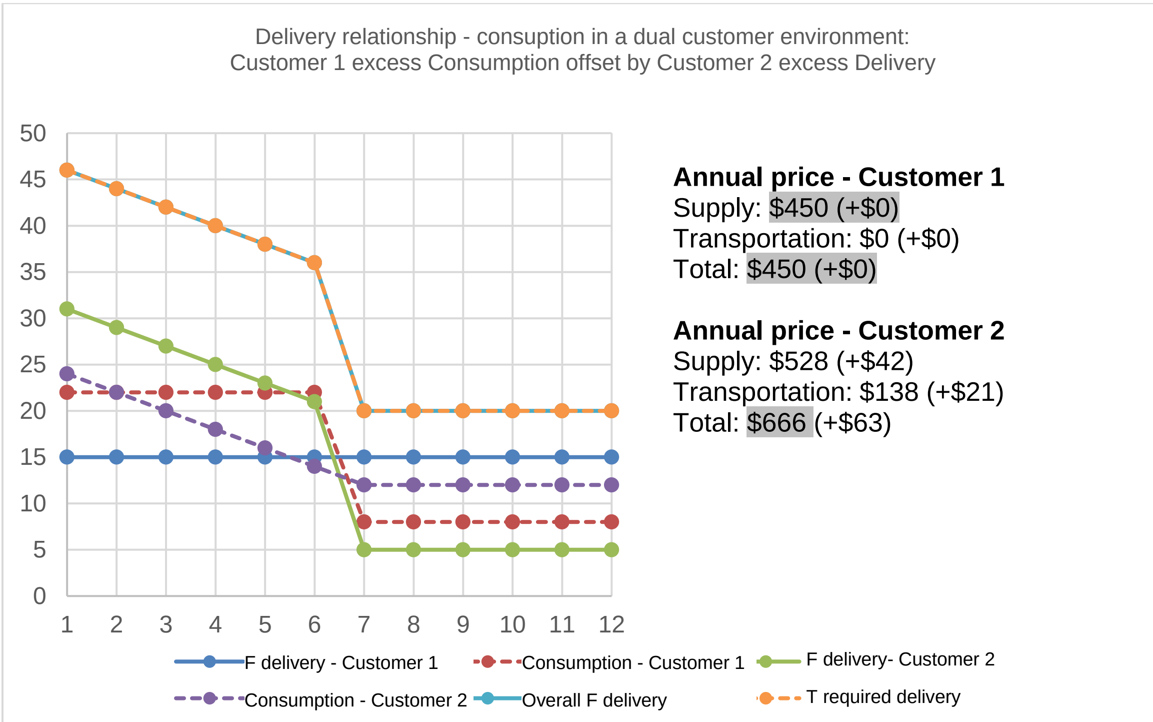
Graph 43



Not only do the transportation costs remain the same, but the reduction in Customer 1's costs is entirely offset by the increase in Customer 2's costs. The transportation costs also remain the same because the variation in delivery does not affect the demand by the franchise. Therefore, when delivery to the reference point outside of Québec deviates from the uniform profile, the additional costs charged to Customer 2 stem only from the supply prices.

Graph […] 43 presents the impact of the delivery profile at a constant consumption profile. Alternatively, Graph 44 presents the impact of the consumption profile at a constant delivery profile. Graph […] 44 illustrates that when the consumption for a customer who delivers its supply to a reference point outside of Québec deviates from the uniform profile, the additional costs charged to Customer 2 stem from the supply prices and the additional transportation capacities. The delivery profile for Customer 1 at the reference point outside of Québec therefore does not have a reciprocal impact on its consumption profile, unlike a customer who delivers to the franchise.

Graph 44



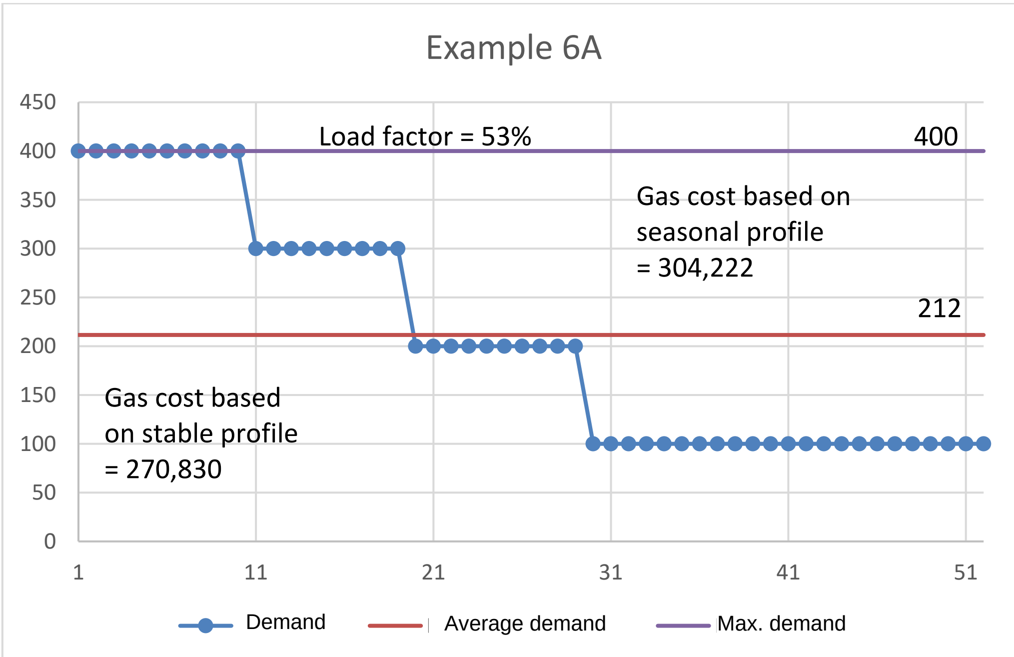
As a follow-up to decision D-2016-156, an analysis was conducted on the impact of natural gas deliveries by direct-purchase customers. Since the concepts analyzed in this additional evidence (R-3867-2013, B-0188, Gaz Métro-5, Document 7) remain unchanged and the Énergir proposal does not address non-uniform deliveries, the original version can be consulted if necessary.

2.2.7. Supply storage

To avoid having to buy more supply during the winter, the distributor may store natural gas. Already, to optimize transportation costs, storage in franchise is contracted. In addition, the distributor may purchase storage outside the franchise to reduce its natural gas purchases in winter and replace them with summer purchases.

To illustrate this, let us return to example 6A, in which the customer makes its own supply purchases:

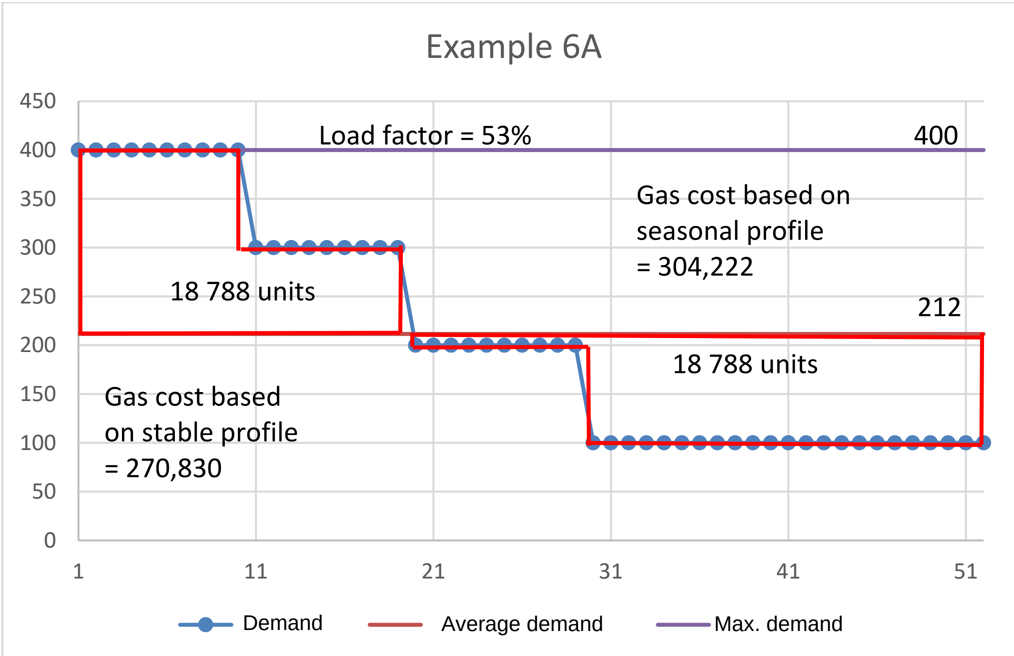
Graph 45



To balance this customer, the distributor must purchase additional quantities of natural gas during the winter and sell the excess received during the summer.

However, rather than spending variable amounts based on price fluctuations and to avoid purchasing and reselling natural gas to balance the customer, the distributor can purchase storage capacity:

Graph 46



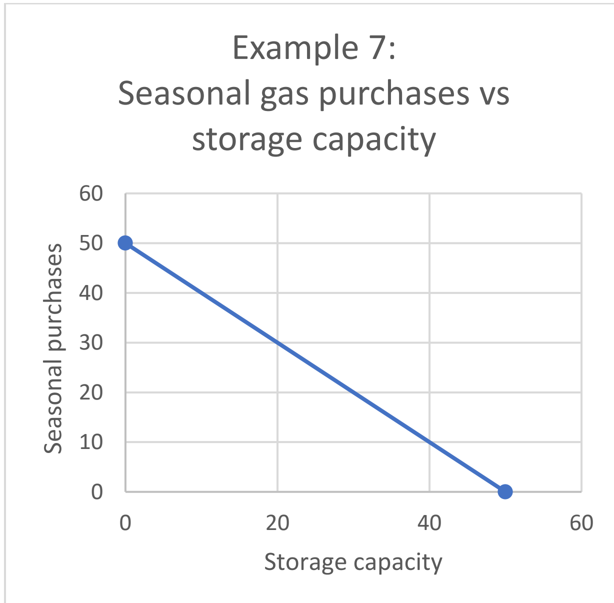
By contracting 18,788 units of storage capacity, in order to inject 112 units per day in summer and withdraw 188 units per day in winter, the distributor will not have to purchase and resell supply for this customer.

If the storage is already required for transportation tool optimization needs (storage in franchise), then this tool can also be used to balance supply.

If the storage is not in franchise, the cost of the storage contracts, including injections and withdrawals, are all replacement costs for the purchase and resale of the supply which would otherwise be required. In the example presented, the cost of 18,788 units of storage capacity will replace the $33,392 generated by the seasonal supply consumption.

The greater the storage capacity, the smaller the gap between seasonal purchases and uniform purchases. This dynamic can be illustrated as follows:

Graph 47



For example, for a seasonal need of 50 units in winter, when the storage capacity is zero, the supply purchase in winter must be 50 units higher than uniform purchase, and the purchase in summer must be 50 units lower than uniform purchase. However, with a storage capacity of 50 units, the supply purchase can be uniform all year long.

The storage costs will be more stable over the years, while the cost of seasonal purchases will change based on market prices. However, since storage is used to replace seasonal purchases, these costs are still attributable to all customers with a seasonal purchase profile, whether they are in the distributor's supply service or they purchase their own supply. A greater proportion of the storage costs will be allocated to customers that would have created the greatest seasonal cost if the distributor had not opted for the storage solution.

2.3. OTHER FACTORS

2.3.1. Causation of supply purchase and transportation costs from different physical locations

When the services are unbundled, as was the case for supply, transportation and load-balancing, the distributor has to have rates comparable to the costs that a customer would have to pay if it did not use the distributor's services and instead procured them on the market. For this to be the case, the functionalization of the costs among the services must provide costs that reflect the established causation while making sure that the rates stemming from this functionalization are not to the detriment of the distributor's service over the market or vice versa.

Therefore, when the supply is purchased from different purchase points, the causation observed remains the same as when all purchases are made from the same physical location: the costs are allocated based on a uniform profile and a seasonal profile. Furthermore, the distributor's supply purchase price for different purchase points must be established at the price of the delivery point for customers that provide their own supplies (also called the "reference point").

Based on a uniform purchase profile, the simple difference of annual cost between the reference point and the different purchase location can appropriately determine the cost of the supply and the transportation cost.

For example, here is a table showing the annual cost of supply at four different points:

Table 14

Annual cost at various locations ($)

Place of purchase	Annual cost	Benchmark differential A	Benchmark differential B	Benchmark differential C	Benchmark differential D
A	3	0	-1	-2	-3
B	4	1	0	-1	-2
C	5	2	1	0	-1
D	6	3	2	1	0

The annual cost at the reference point is equal to the uniform supply cost, while the differential with the reference point is equal to the delivery cost for uniform consumption.

The difference between the cost realized based on non-uniform purchases and the annual cost can only be related to a seasonal purchase profile.

Here is a second table showing the annual cost based on a uniform profile and the real cost per point, using purchase location a as the reference point:

Table 15

Cost per location with A as the reference point ($)

Place of purchase	Annual cost	Actual cost	Uniform supply cost	Uniform delivery cost	Non-uniform cost
A	3	4	3	0	1
B	4	4	3	1	0
C	5	6	3	2	1
D	6	5	3	3	-1
Allocation			Uniform profile	Uniform profile	Seasonal profile

As a result, when the supply is purchased from several different locations, the supply cost must always be equal to the annual cost at the reference point, based on a uniform delivery profile. Then, the gap in relation with the real purchase cost must be separated based on the cost origin. When the cost is caused by uniform purchases, it must be allocated to the customers' portion of uniform consumption (units used). The costs arising from non-uniform purchases are automatically incurred to meet the customers' seasonal needs. These costs must be allocated based on the customers' seasonal consumption profile.

2.3.2. Causation of costs related to inventory maintenance for supply and transportation

We saw earlier that to optimize the costs associated with transportation and supply purchase, contracts are made for storage. But beyond the cost of the storage tool, maintaining an inventory in these storage sites generates financing costs, as well as costs related to "support" for price variations over time. Once again, to determine the allocation required for the cost of inventory, we need to examine the causation.

Maintaining an inventory only serves the needs of customers with a seasonal profile, because the uniform portion of the demand requires no inventory. The costs related to inventory that seek to reduce to load-balancing costs must therefore be broken down based on the seasonal consumption profile. However, in specific cases where the use of warehousing tools would be aimed at optimizing transportation costs or operational flexibility needs, the inventory costs should instead be allocated by the allocation method associated with these functions.

Currently, customers that provide their own natural gas through direct purchases without transfer of ownership and customers that provide their own transportation are not invoiced for amounts related to inventory (articles 14.2.1 and 14.2.2 of the *Conditions of Service and Tariff*). Is this still appropriate? Should these costs only be allocated to the distributor's customers that are charged a supply cost (customers in the distributor's supply service and customers that use direct purchase with transfer of ownership)?

We demonstrated in section 2.2.7 that storage could reduce seasonal supply purchase and resale transactions by injecting excesses during the summer and withdrawing them during the winter. This method allows for reducing seasonal purchases in winter, which means the cost of storage replaces the cost of seasonal purchase.

Since the cost of seasonal purchase is generated by both customers that provide their own supply and those that use the distributor's supply service, the replacement cost should be considered to be generated by all customers equally. The variation in the annualized cost between the time of injection and withdrawal, as well as the financial cost of maintaining the inventory, should therefore be supported by all customers, as are the costs of seasonal purchases by all customers.

2.3.3. Operational flexibility

Until now, to examine the causation of supply purchase costs and transportation tools, one of the basic assumptions has been the lack of constraints related to operational flexibility due to the variation in demand over the course of a day.

In reality, however, daily demand always varies a little. This demand projection is processed in the planning for the gas day on the previous day. Other than this daily variation, an adjustment of supplies during the day may be required to more accurately meet real customer demand and injection needs, when required. For example, to secure the supply adjustment over the course of the day to the extent possible, a margin is added to the projected demand, either an increase in winter, because it is easier to decrease supply than increase it, or, inversely, a decrease in summer, because it is easier to increase supply than decrease it. This adjustment during the course of the day is identified as operational flexibility

To make these adjustments, it is not enough to have supply tools that supply natural gas on a daily basis. We also need to have tools that allow for changes in the quantities delivered over the course of the day. In terms of natural gas supply, we also need tools to handle an increase or decrease in the need for the commodity.

A totally stable customer, i.e. one that consumes exactly the same volume every day and at every moment of the day, which is practically impossible, does not need any operational flexibility, so to speak. Its daily need never has to be changed. In any case, it still benefits from Énergir's management method to ensure supply security for all its customers. Furthermore, if this customer had a breakdown that caused a temporary closure, its profile would no longer be totally stable. It is therefore not protected from the need for operational flexibility.

Therefore it appears inappropriate to allocate operational flexibility costs based specifically on a stable equivalent profile.

Does that mean that the cost of operational flexibility related to transportation tools or supply purchase should be allocated based on the customer's consumption profile? No, essentially for two reasons:

- The seasonal consumption profile of all customers is just in the winter, but the need for operational flexibility is year-round.
- The need for operational flexibility is not related to the customers' LF.

If customers always consumed the exact supply quantity projected, there would be no need for operational flexibility. But it is not because a customer's consumption is related more to temperature that it generates greater gaps in demand in a day in relation with the projected demand. This explains why the operational flexibility need is present both in the summer and winter.

Neither the stable consumption profile nor the seasonal consumption profile causes the need for operational flexibility. And as is the case for stranded costs not related to temperature, previously discussed in Section 2.1.5, it is practically impossible to connect:

- The gap between real daily consumption and planned global consumption for all customers; and
- The variation in a particular customer's real and planned consumption, since this kind of daily planning does not exist.

Here are some examples illustrating the difficulty of breaking down these costs among the customers:

On one day, the distributor expects to deliver 100 units to the franchise. But one customer consumes 10 units less than expected. The distributor must therefore adjust the nomination downward. The cost of operational flexibility, for that day, could be attributed to the customer that consumed less than the distributor projected.

The next day, the distributor once again expects to deliver 100 units to the franchise. That day, everything goes as planned. The cost cannot be attributed to any particular customer.

Finally, on another day, the distributor once again expects to deliver 100 units to the franchise. One customer consumes 10 units less than projected and another one consumes 5 more than projected. In total, the distributor has to adjust the nomination downward. In this case, is the customer that consumed less than projected responsible for all of the flexibility costs? Although, while the higher consumption for the second customer reduced the gap, it still consumed a different volume of natural gas than expected. In addition, projections are made globally by the distributor and may differ from what each customer itself expects to consume. If two customers consumed what they each personally projected, can the distributor's projection gap be directly allocated to either of them?

In reality, all customers may have variations in consumption every day. The distributor builds a template that tries to summarily determine the daily need based on all these variations. However, regardless of the template, there will always be gaps between the distributor's projection and the daily need of all customers. It is practically impossible to break down and allocate the costs related to operational flexibility directly to particular customers, or even to establish a specific profile for doing so.

That said, the greater the volume consumed by a customer, the greater the risk it will have a significant impact on demand when its consumption differs from the projection. It is therefore reasonable to believe that the need for operational flexibility is related to the consumption of all customers.

In conclusion, the operational flexibility costs related to transportation tools and supply purchase must be allocated separately, in order not to penalize a specific type of customer. Since the need for operational flexibility increases with the total volume to supply, the most direct causal link for operational flexibility is the volume consumed by the customers.

2.3.4. Determination of the peak demand observation period

The LF, which measures seasonal weight in a given consumption profile, is defined as follows:

$$\mathrm{LF} = \frac{\text{Annual average}}{\text{Winter peak}} = \frac{A}{P}$$

The notion of "annual average" is simply the annual consumption divided by 365 or 366 days. However, the notion of "winter peak load" has not been defined until now.

Currently, the parameter of peak personalized load-balancing price, where the "winter peak load" is defined in the *Conditions of Service and Tariff* as the maximum daily load from November 1 to March 31.

Insofar as the franchise peak influences most of the load-balancing costs, the observation period for the winter peak must minimize or even eliminate the risk of excluding the franchise's peak day. In fact, this is the day on which customers are most likely to hit their heating peak. This risk increases when we narrow the peak observation window.

On the other hand, the winter peak observation period must minimize the risk of capturing an individual peak that does not correlate with the franchise peak. An individual peak that correlates weakly or not at all with the franchise peak will have little impact on the load-balancing costs (or no impact at all, if the peak happens during the summer). This risk increases the longer the observation period extends.

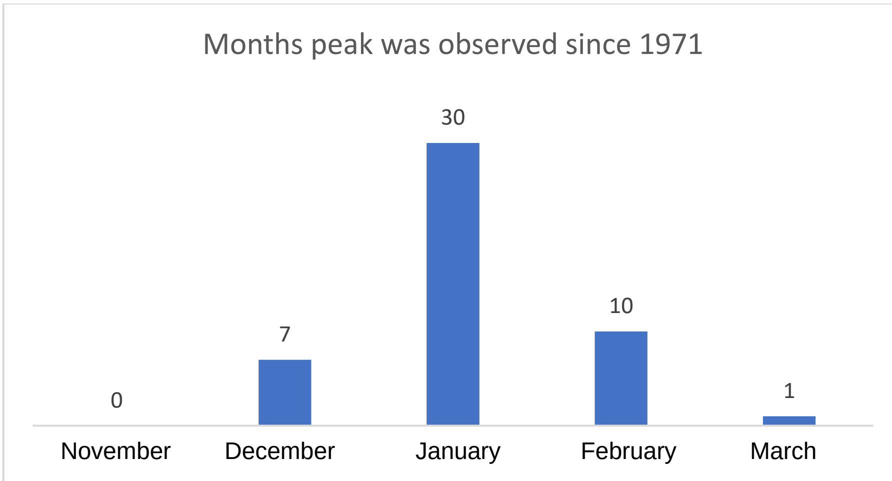
By meeting these two objectives, the peak observation period will reinforce the price signal, which aims to flatten out customers' seasonal load profiles.

<u>Minimize the chances of excluding the franchise peak</u>

Énergir conducted an analysis of the increase in daily temperatures since 1971, in order to determine a breakdown of when the coldest temperature occurs within the five months of the current peak observation period: November, December, January, February, and

March. Énergir makes the realistic assumption that the highest demand is seen during the coldest day.[10]

Graph 48



Over the past 48 years, the peak was observed 30 times in January, 10 times in February, 7 times in December, and once in March. The peak temperature in March was -20.1°C. The coldest day of the year has never been observed in November. The coldest temperature observed in November in the past 48 years is -13°C, while the warmest peak winter temperature during the same period is -14°C. The probability of the observed peak being -13°C is less than 1% (assuming a normal distribution[11]).

Given these observations, we could consider excluding March from the observation period. In fact, the information obtained during the coldest day from December to February when the peak occurred in March allowed to truly capture the heating profile. For example, when the peak of -20.1°C was observed in March, the coldest temperature from December to February was -19.6°C. The customer heating profile recorded at a temperature of -19.6°C is likely very similar to that recorded at -20.1°C. In this example, the differential generated by excluding the month of March is marginal. And, since the peak occurred in

[10] See Graphs 1.3 to 1.7 in Appendix 1.

[11] A Jarque-Bera test was performed to test the assumption of normality of the peak temperature; we cannot reject the normality assumption.

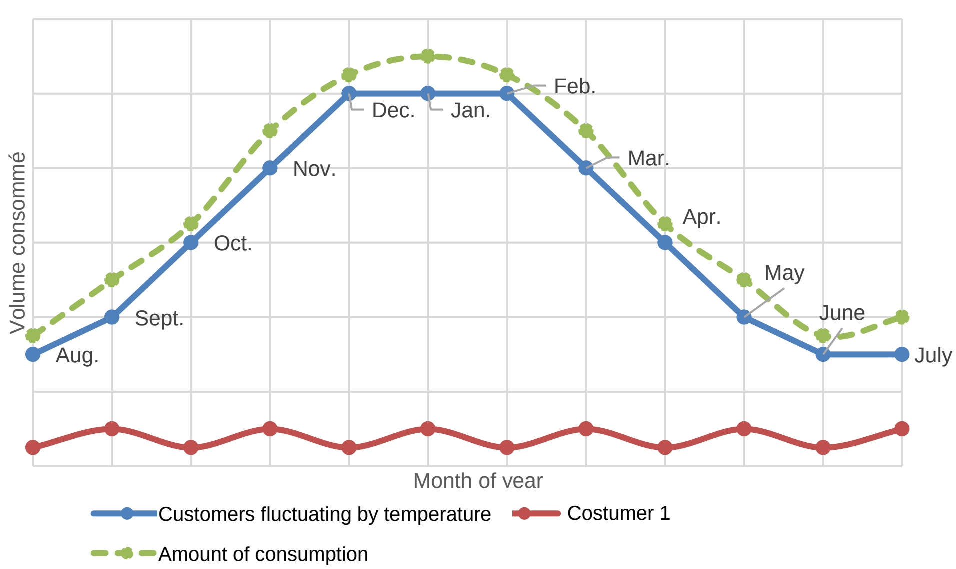
March only once in the past 48 years, this marginal differential should be observed only rarely.

<u>Minimize the risk of recording individual peaks not correlated with the franchise peak</u>

While temperature is the explanatory variable for the overall consumption profile of Énergir's customers, it does not necessarily explain customers' specific consumption profiles. Graph 49 and Graph 50 illustrate a theoretical environment for two types of customers: customers who are mainly affected by the temperature (Customers with consumptions affected by temperature fluctuations) and customers who are not affected by the temperature (Customer 1 and Customer 2). For simplification purposes, the volume withdrawn by heating customers is higher and level from December to February because, historically, 98% of the time the coldest temperature has occurred during these months, and because identifying a certain month as being the coldest is not necessary for this demonstration.

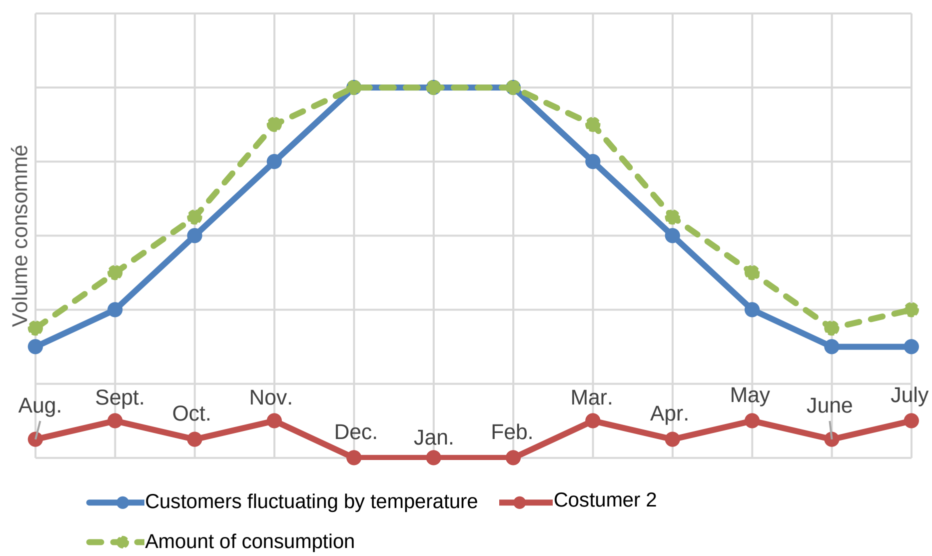
Graph 49 illustrates that Customer 1 contributes to the franchise peak, defined as the maximum total consumption observed in January. It must therefore pay a share of the load-balancing costs associated with the peak.

Graph 49



Graph 50 illustrates that Customer 2 does not contribute to the peak observed in December, January, and February because the customer withdraws nothing during these months. However, it withdraws in November and March, but this has no impact on the load-balancing costs associated with the peak.

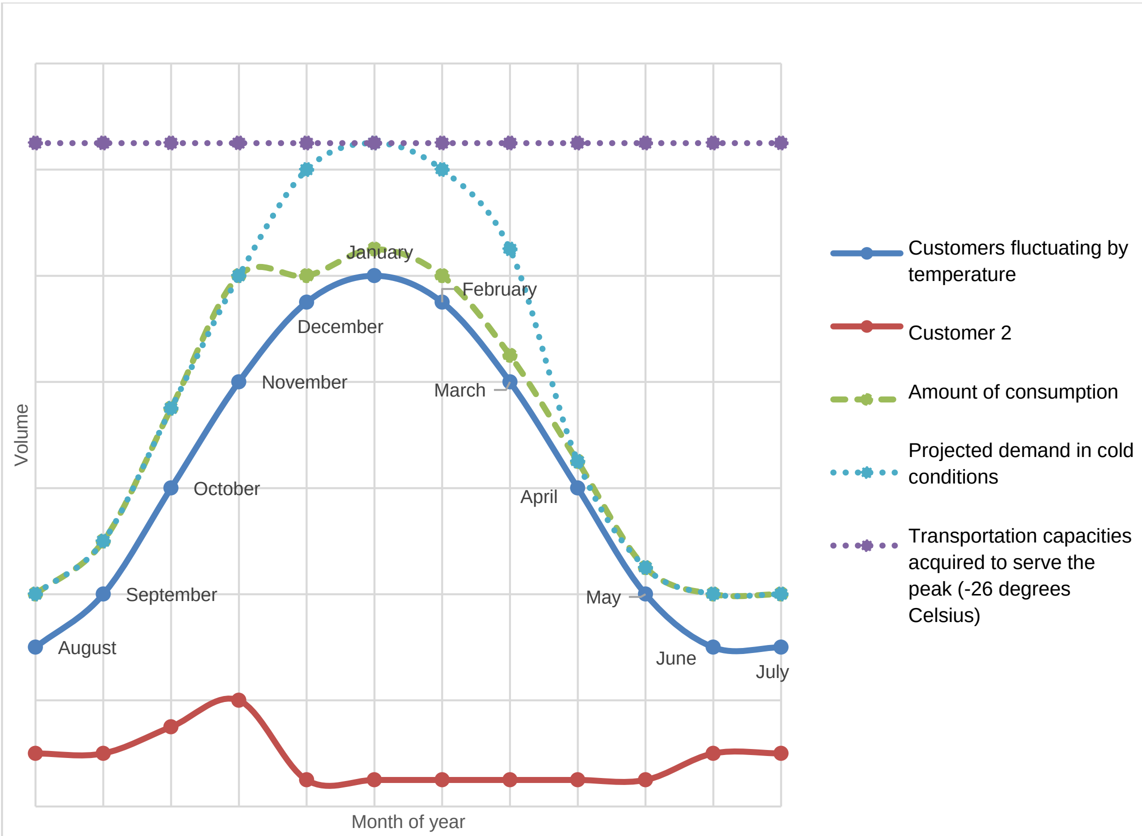
Graph 50



Énergir conducted a consumption analysis on a sample of its customers and found that certain customers systematically know their winter peak load for November.

Based on the analysis of historical temperatures, Énergir notes that the customers who systematically know their peak consumption for the pivotal months (November and March) are allocated load-balancing costs associated with a seasonal profile, whereas they do not generate any cost during the distributor's peak day. Graph 51 illustrates this finding, always in a theoretical context.

Graph 51



Customer 2, who is not affected by temperature, still experiences a winter peak in November depending on the actual conditions, but has no impact on costs, which are generated by the projected customer demand during a cold winter.

The observations on temperature and on the consumption profile of certain customers therefore lead us to propose a change to the peak observation period. By excluding November and March:

- we reduce the inclusion of independent temperature peaks that have no impact on the costs associated with serving the franchise peak;
- we do not reduce the information used to estimate the customer's heating profile, since the coldest days are always observed between December and February (barring exceptions).

This correlation, which is more representative of the causation of peak period costs, is why Énergir proposes a new definition of peak period in Section 3.5.1 of exhibit Gaz Métro-5, Document 14.

3. AVERAGE DEMAND AND SURPLUS METHOD

3.1 HISTORY OF THE FUNCTIONALIZATION METHOD

In decision D-97-047, the Régie retained the proposal made by *Approvisionnements Montréal, Santé et Services Sociaux* (AMSSS)[12] as a method for unbundling transportation and load-balancing costs: average and excess demand.

According to this method, the transportation and load-balancing tarification must be fair for customers of any consumption profile types. The average and excess demand method is relatively simple:

- The average demand (the customers' real consumption) determine the costs associated with transportation.
- The excess over the average demand, of any sort (transportation or load-balancing tool), must be associated with load-balancing.

The average demand is associated with a LF of 100%, i.e. the equivalent of completely stable consumption, which ensures the fairness of the rates.[13]

In terms of transportation, the allocation to all customers, including interruptible customers, of a per-unit cost equivalent to the firm transportation cost at 100% LF was appropriate, according to the Régie. Furthermore, this separation then allows for a distribution of storage costs that took consumption profiles into account and recognize the contribution of interruptible customers.[14]

[12] File R-3323-95, Cigma, Evidence of Sharon L. Chown on behalf of Approvisionnements-Montréal and Novagas Clearinghouse Limited.

[13] See Appendix 2 for a more complete definition of the average and excess demand method.

[14] D-97-47, Section 5.4.

For the costs that exceed the average demand, the method proposed by the AMSSS allows for the costs to be divided as follows:

- Seasonal storage capacity (Dawn): Excess of average winter demand compared to average annual demand. The cost of seasonal storage here also includes the cost of FTSH to deliver the supply from Dawn to Montreal.
- Leading-edge storage capacity and transportation in excess of 100% LF. (Pointe-du-Lac, LSR plant): Excess on peak theoretical day compared to annual demand.
- Interruptible customers: Credit equivalent to costs avoided to serve customers in firm service.

The Régie retained this method, but asked for certain items to be modified:[15]

- It concluded that there was an overlap in the proposed calculation method for the storage costs allocated to the customers, because the volumes used to determine the gap between the theoretical peak day and the annual demand (**P** - **A**) were already included in the calculation to determine the gap between the average winter demand and the annual demand (**W** - **A**);
- It was of the opinion that a cost of use should be attributed to the interruptible customers.

To adapt the AMSSS proposal and avoid duplicating the volume calculation, Énergir proposed to calculate the peak using the excess of the peak day over the average winter demand (**P** - **W**) (R-3426-99, SCGM-10, Document 1, p. 22). This way, the total gap between the peak and the annual demand was subdivided into two parts: (**P** - **W**) and (**H** - **A**).

In the same exhibit, with regard to the credit to be extended to customers, Énergir proposed sharing the savings equally between continuous service customers and interruptible service customers (50% - 50%). Énergir proposed using a peak of zero for the interruptible customers.

Furthermore, to institute this division, Énergir performed calculations to determine the reduction offered in the interruptible service by combining the total cost of transportation and distribution for

[15] D-97-047, p.22

the interruptible services. The results of these calculations justified the various rate changes for the “improved” interruptible service.

Based on these findings, Énergir proposed the following calculation to allocate the load-balancing cost (R-3443-2000, SCGM-2, Document 1, p.47):

$$\frac{\text{“Peak” price} \times (\mathrm{P} - \mathrm{W}) + \text{“Space” price} \times (\mathrm{W} - \mathrm{A})}{\text{Volume for the last 12 months}}$$

The situation at the time lent itself well to this kind of cost separation. At that time, annual demand was entirely supplied out of Empress. Furthermore, the combined cost of storage at Dawn and FTSH transportation, STS in this instance, was lower than the cost of FTLH transportation from Empress to Montreal. The supply was therefore transported in summer from Empress to Dawn, where it was stored. In winter, the supply was delivered from Dawn to Montreal. The cost of storage at Dawn replaced the excess FTLH transportation cost in winter with a lower cost.

However, beginning with the 2005 Rate Case, this situation changed.

> “*Previously, to meet the annual and seasonal demand of its customers, SCGM fully used its long-haul transportation capacity in winter*. […] *To reduce costs, SCGM reduced its long-haul capacity and replaced this transportation with purchases at Dawn.*” [translation][16]

Énergir also introduced a mechanism whereby the savings from purchases at Dawn would be recorded entirely in load-balancing:

> “The benefits arising from this new supply strategy were not felt in the transportation service, but in the load-balancing service.” [translation][17].

This mechanism attributed the excess cost of FTLH purchases compared to purchases at Dawn to transportation, which resulted in a reduction in load-balancing costs. In the rate-setting exhibits, this resulted in a transfer of costs from the load-balancing service to the transportation service.

Likewise, in the same case, rather than separate the space and peak costs by functionalizing the storage tools in terms of space or peak (at that time, only the PDL and LSR storage tools were functionalized by peak), Énergir proposed instead to rank the tools and observe their position in relation to average annual demand, average winter demand and peak demand. The tools were

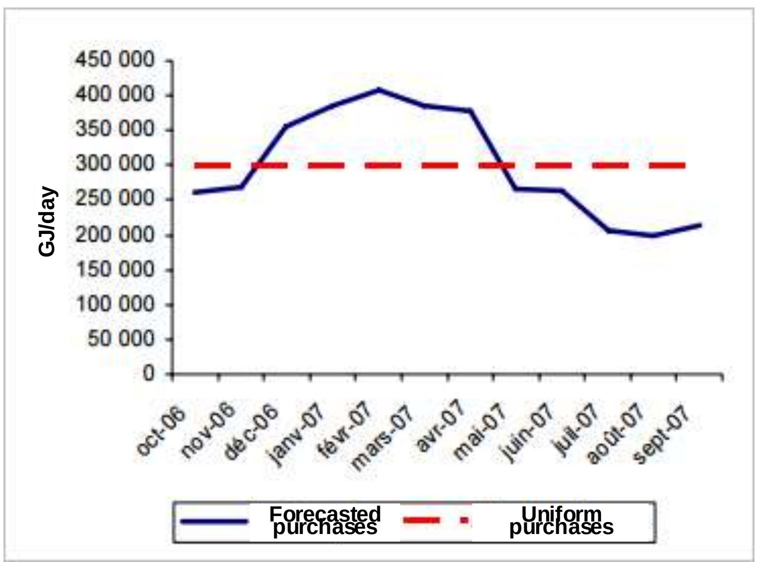
[16] R-3529-2004, SCGM-11, Document 1, p.3.
[17] R-3529-2004, SCGM-11, Document 1, p.4.

then functionalized between space and peak, based on the percentage received during the ranking.[18] This methodology functionalized the costs between peak and space to reflect the method used to establish the peak and space prices, leading to coordination between costs and revenues. The Régie approved the new methodology in decision D-2004-196.

Two changes subsequently occurred concerning cost functionalization.

First, in the 2008 Rate Case (R-3630-2007), following the D-2006-140 decision, Énergir examined cross-subsidization based on the natural gas supply purchase profile. This document showed that gas network purchases were not uniform (R-3630-2007, Gaz Métro11, Document 1, p. 11):

Graph 52



As the price of the supply changes each month, the average purchase price based on the projected profile was inevitably different from the average purchase price based on the uniform profile. Consequently, the gap between the average purchase price based on the actual profile and the average purchase price based on the uniform profile was automatically related to the customers' need for load-balancing. The method retained to correct the cost of the supply so it

[18] R-3529-2004, SCGM-11, Document 1, p.7.

would reflect the exact cost of the average purchase price based on the uniform profile was to transfer the difference in dollars of the supply cost to the load-balancing cost.

Another amendment had to be made when the quantities purchased at Dawn began to comprise a significant portion of the total supply purchases.[19] Since all the savings related to purchases at Dawn were considered in load-balancing, the growing purchases at Dawn increasingly reduced the total load-balancing cost. As the savings in the load-balancing service were higher than the cost of transportation from Dawn to Montreal, they also reduced other costs, such as the cost of the storage sites. The costs functionalized to load-balancing therefore no longer represented the excess of average demand. By further increasing the purchases at Dawn, Énergir also predicted that all load-balancing costs would risk ending up lower than zero, which in itself did not reflect reality, since load-balancing was actually offered to the customers. Énergir therefore reviewed the way the transportation costs were functionalized. The review allowed for re-establishing the load-balancing costs in the 2012 Rate Case so they would once again reflect the excess of average demand.

3.2 WHY A NEW METHOD OF FUNCTIONALIZATION IS REQUIRED

Following the analysis of the cost causation of supply costs presented in Section 2, costs in the preceding sections, Énergir has arrived at the same conclusion: the use of a uniform consumption profile (average demand) to determine transportation costs generates a fair transportation price for all customers, whether or not they use the distributor’s service. The excess costs can then be functionalized to load-balancing and allocated more accurately, taking consumption profiles into account.

Énergir therefore believes that the basis of the average and excess demand method retained in decision D-97-047 is still appropriate today. However, certain adjustments are required.

After the rates were unbundled, Énergir suggested a method of functionalizing the transportation costs that would comply with the average and excess demand method by first evaluating the costs for an average demand at 100% LF. These costs essentially corresponded to the cost of FTLH

[19] 2012 Rate Case, R-3752-2011, Gaz Métro-12, Document 1, Section 4.

transportation between Empress and the Énergir territory. The costs of the other tools were functionalized in the load-balancing service.

From the time when purchases at Dawn increased considerably, Énergir began to functionalize part of the FTSH transportation tools in transportation.[20] Since the annual demand in a normal winter does not take up all the annual transportation tools, to charge costs to transportation, Énergir suggested a method based on the ranking of the gas supply tools that reflected the real use of each tool. This method is the one still used today. The capacities assigned to transportation correspond to the cost of the tools used successively until the average annual demand at normal temperatures is filled. Briefly, the order of use of the tools at that time was as follows:

I. FTLH transportation tools

II. Dawn FTSH transportation tools

III. Parkway FTSH transportation tools

IV. STS transportation tools

The cost of the tools is therefore recorded in full in transportation until one of these tools exceeds the average annual demand. The tool that exceeds this demand is then allocated proportionally between transportation and load-balancing. The transportation tools of each type are not separated between tools that can transport supply for the entire year and those that can transport it only seasonally.

In the rate case, this method complies with the principles of average and excess demand. By performing the calculation based on average demand to record the costs in transportation and load-balancing, the LF is 100%, by definition. However, this theoretical calculation will certainly be different from the reality observed at the end of the year. In fact, depending on winter temperatures and the difference in volume forecasts at the beginning of the year, the average demand noted in the annual report is different from the average demand estimated in the rate case.

[20] 2012 Rate Case, R-3752-2011, Gaz Métro-12, Document 1, Section 4.

By maintaining the same proportion of tools allocated to the rate case as for the annual report, the allocated costs no longer represent a LF of 100%. The overpayment or shortfall in the transportation service therefore definitely includes a cost increase or reduction related to the seasonal consumption profile. By extension, the load-balancing service has a cost reduction or increase related to the stable consumption profile.

To correct this situation, Énergir suggested[21] reviewing the ranking at the end of the year so that the costs allocated to the transportation service always represent a LF of 100% in both the rate case and the annual report. This solution was not retained by the Régie, however.[22]

Since then, the Régie has required follow-up on the functionalization of costs between the transport and load-balancing services, including the functionalization of the natural gas purchase premium.

Therefore, considering the entire case since the unbundling of the rates, Énergir believes that a new cost functionalization method is required. The new method will have to comply with the principle of average and excess demand in today's context and be able to adapt to future changes.

In addition to the tool-ranking method that essentially functionalizes the transportation service costs associated with seasonal profiles and based on winter temperatures, there are two other reasons why a new functionalization method that is consistent with the established causal links is needed:

- The supply costs are indissociable from each other. The acquisition of additional tools is always based on total demand, i.e. the sum of stable demand and seasonal demand. These costs should be processed globally at the beginning;
- Stranded costs[23] are costs associated with unused capacity and should be reflected directly in load-balancing.

[21] R-3837-2013, B-0256, Gaz Métro-2, Document 4, Section 4.
[22] D-2014-065, A-0151, Section 3.6.3.
[23] See Section 2.1.5 for this.

These three issues are resolved in the following sections, which present the proposed method for functionalizing costs between services, fully reviewed and adapted to the causation chosen.

4. RECONCILING THEORETICAL PRINCIPLES AND PRACTICAL APPLICATION

IMPORTANT

The text contained in this section does not appear in documents previously filed in the file. This section is an addition.

Sections 1 to 3 have illustrated the logic behind Énergir's supply requirements. To elaborate on how this logic applies to the supply plan, this section demonstrates the tangible links between theory and the supply plan.

4.1. CHANGE IN SUPPLY REQUIREMENTS

The supply plan is set up to meet overall customer demand. To find out the capacity required for a specific year, the first step is to calculate the need on a very cold day. The peak demand on a very cold day is then compared with the capacities already contracted for transportation and in-franchise storage. Based on the results, an adjustment is then planned: purchase additional capacity when the peak demand is greater than the capacity contracted, or sell capacity when the peak demand is less than the capacity contracted. Secondly, if these peak capacities include in-franchise storage, a test must be conducted to ensure that the inventory of these sites will be able to meet the requirements of a very cold winter, typically called an extreme winter.[24] If there is not enough inventory to deal with an extreme winter, Énergir must adapt its plan to ensure that it can respond to such a scenario.

Once the needs have been determined, Énergir can optimize the structure of the tools available on the market and try to reduce its total purchasing costs. At no time is a strictly "transportation" requirement considered at this stage, because the determination of this specific element does not

[24] R-4119-2020, B-0113, Énergir-H, Document 1, Appendix 7.

affect the results of the steps to determine supply requirements or the cost optimization of the plan.

Normally, the capacity of the tools contracted for a year corresponds to the peak need on a very cold day. However, when transportation tools are replaced with in-franchise storage tools, the reduction in transportation tools may be less than the withdrawal capacity of the storage site. In this case, the total potential withdrawal capacity of the tools acquired would exceed the peak need on a very cold day.

4.2. PROJECTING DEMAND IN THE SUPPLY PLAN

Volumes projected for both peak day demand and winter projections are based primarily on the results of a decrease in the previous winter's volumes. The main factors in the decline are the degree days,[25] the previous day's degree-days and the degree-days * wind combination. Temperature variation essentially explains all winter requirements, with a correlation coefficient above 0.9. This is in line with the theoretical demonstration provided earlier of the relationship between costs and temperature.[26]

For normal winters, daily volumes are calculated based on the decrease and then adjusted to match the monthly volumes anticipated in the demand forecast. For the other scenarios, daily volumes are adjusted using the decrease based on the difference in degree-days, the previous day's degree-days and the degree-days * wind factor.

Thus, the supply plan considers the variation in winter temperature the only factor explaining the variation in demand. This variation reflects the variable heating needs of customers. Therefore, in the supply plans, the variable portion of average winter demand depends on the same explanatory factor as the surplus between average and peak demand.[27]

[25] Difference between the 13°C threshold and the average daily temperature; degree-days are used to determine heating volumes relative to the outdoor temperature.

[26] See sections 2.1.1 to 2.1.4 on cost causation.

[27] This topic is analyzed in Appendix 4.

4.3. COST VARIATION IN THE SUPPLY PLAN

In general, the transportation and warehousing tools available to meet the capacity required on peak days have a high fixed cost and a low variable cost. So this dynamic means that the costs variation for transportation and balancing in franchise is mainly due to the change in capacity requirements rather than to the use of the in-franchise sites' inventory.

On the supply side, costs vary based on market prices. Supply costs will therefore depend on customer demand. Since supply costs are generally higher in the winter months, cold winters are more expensive than warm winters. The use of storage sites can reduce costs during cold winters, as they are usually filled during the summer months when supply costs are lower.

4.3.1. Cost variation based on a constant peak and variable volume in the winter season

To illustrate this dynamic, here are the costs in the supply plans of the 2020-2021 Rate Case for warm, normal and cold winters:

	Warm	Normal	Cold
Volumes ($10^6 m^3$)	6,156	6,353	6,515
Degree-days (December to March)	1,920	2,268	2,574
Peak day need ($10^3 m^3$)	36,723	36,723	36,723
LF (%)[28]	45.9	47.4	48.6
Costs ($M)			
Transportation tools	237.9	238.6	238.8
Storage tools[29]	38.7	38.7	40.1
Supply	658.5	681.4	699.8
Total	**935.1**	**958.7**	**978.6**
Cost ($) per m^3	**0.152**	**0.151**	**0.150**

[28] It should be noted that the CU in this table is presented for information purposes only, since, unlike the CU projected in the tariff case, it does not affect the advanced tools contracted by Énergir. Comparing the effects of CU on gas supply needs and costs requires comparing scenarios with the same temperature profile.

[29] Including inventory maintenance.

Compared to the normal winter, volumes decreased by 3.1% in a warm winter and increased by 2.5% in a cold winter.

Despite this volume variation, transportation and storage costs changed little in either scenario. As such, the costs decreased by 0.3%[30] in the warm winter and increased by 0.6%[31] in the cold winter.

Supply costs were down 3.4% when the winter was warm and up 2.7% when the winter was cold, i.e. in a proportion that slightly exceeded the change in volumes.

Including supply costs, the volume variation generally exceeds the cost variation, showing that the unit cost changes in the opposite direction to the volume variation. This demonstrates that an increase in volume leads to a decrease in unit costs, while a decrease in volume leads to an increase in unit costs.

4.3.2. Cost variation based on variable peak and constant load factor

The variation in peak need has nonetheless a greater effect on supply costs. Here are the costs in the supply plan of the 2020-2021 Rate Case for a normal winter for the benchmark favourable and unfavourable scenarios:

[30] (237.9 + 38.7) / (238.6 + 38.7) - 1 = -0.3%.
[31] (238.8 + 40.1) / (238.6 + 38.7) - 1 = +0.6%.

	Unfavourable	Benchmark	Favourable
Volumes ($10^6 m^3$)	6,186	6,353	6,459
Degree-days (December to March)	2,268	2,268	2,268
Peak day need ($10^3 m^3$)	36,002	36,723	37,297
LF (%)	47.1	47.4	47.4
Costs ($M)			
Transportation tools	231.7	238.6	243.3
Storage tools[32]	38.7	38.7	38.7
Supply	663.5	681.4	693.0
Total	**934.0**	**958.7**	**975.0**
Cost per m³ ($/m³)	**0.151**	**0.151**	**0.151**

In comparison to the benchmark scenario, volumes declined by 2.6% in the unfavourable scenario and increased by 1.7% in the favourable scenario. As for the LF, it was slightly lower (0.3%) in the unfavourable scenario and almost identical in the favourable scenario. A variation this small is considered a constant LF.

Transportation costs are 2.9% lower[33] in the unfavourable scenario and 1.9% higher[34] in the favourable scenario. Storage tool costs remain the same.

In terms of supply costs, the variation is similar to the volumes. In the unfavourable scenario, costs decrease by 2.6% while they increase by 1.7% in the favourable scenario.

With a relatively similar overall consumption profile, the effect of the variation in transportation costs on the primary market in the favourable and unfavourable scenarios shows that peak demand has a causal effect on the variation in supply costs. For a similar LF, the total costs depend on the volumes consumed, which explains the unit cost remaining constant in these scenarios.

[32] Including inventory maintenance.
[33] (231.7 / 238,6) - 1 = -2.9%.
[34] (243.3 / 238.6) - 1 = + 1.9 %.

4.3.3. Cost variation based on constant volume and variable load factor

When the peak need changes, the supply costs change as well. As long as the LF remains similar, the unit cost will change little, as demonstrated in the previous section (4.3.2). However, a change in the LF directly affects the unit cost. To illustrate this, the consumption profile of customers in the 2020-2021 Rate Case has been changed to increase and decrease the LF (i.e. the effect of each degree-day on customer consumption). In the two alternative supply plans below, one has a higher LF and the other a lower one:

	LF 45.9%	Normal 47.4%	LF 48.9%
Volumes ($10^6 m^3$)	6,353	6,353	6,352
Degree-days (December to March)	2,268	2,268	2,268
Peak day need ($10^3 m^3$)	37,917	36,723	35,555
Costs ($M)			
Transportation tools	249.5	238.6	228.0
Storage tools[35]	38.7	38.7	38.8
Supply	683.2	681.4	679.4
Total	**971.4**	**958.7**	**946.1**
Cost per m³	**0.153**	**0.151**	**0.149**

For similar volumes reflected among the different scenarios, costs vary significantly when the LF changes. This is due to the effect on peak demand. With a lower LF, the peak day need increases, while the reverse is true with a higher LF. In the scenario where the LF decreased, the peak demand went up 3.2%, while in the increased-LF scenario, the peak demand went down 3.2%.

In terms of cost, a decreased LF resulted in $10.9 million more in transportation costs and $1.8 million more in supply costs. When the LF increased, transportation costs declined by $10.6 million and supply costs decreased by $2 million. A slight increase in storage costs of $0.1 million was also recorded.

[35] Including inventory maintenance.

Even when the volumes consumed stayed the same, the change in LF had a direct impact on the unit cost. When the LF decreased, unit costs went from 15.1¢/m³ to 15.3¢/m³. The reverse was observed when the LF increased: unit costs rose from 15.1¢/m³ to 14.9¢/m³.

4.4. Explanatory factor for cost variation applied to the supply plan

Based on these results, the explanatory factor for the variation in Énergir’s supply costs is the LF at normal temperatures.

Thus, when the LF stays relatively the same, unit costs remain stable, even if the volume consumed and peak customer demand change.

Moreover, for a variable LF with stable volumes consumed, the unit costs vary according to changes in the LF.

Finally, even if volumes differ from the normal scenario, unit costs vary inversely with the volumes, regardless of whether the winter is cold or warm. In cold winters, even if the volumes consumed increase, the unit cost goes down. In warm winters, when the volumes consumed decrease, the unit cost increases. This is mainly because the costs of the tools required to meet peak customer demand are mostly fixed.

5. FUNCTIONALIZATION AND CLASSIFICATION OF PROJECTED COSTS USING THE THREE-TIER METHOD

IMPORTANT

Before the results of the cost functionalization by service are presented, it should be noted that the functionalization method applied in this exhibit is different from the one originally proposed by Énergir. For this reason, it is impossible to compare the relative weight of the costs of each service to those in the original exhibit or those obtained using the current method. The new approach to functionalization adopted by Énergir, is described in this section and replaces the old method, as per the recommendations of Elenchus Consulting Services. The results of this step of cost functionalization, obtained using the three-tier method, will be used to determine the results of the next steps, namely allocation and pricing.

In its original exhibit, Énergir submitted the presentation of supply costs to be used in the rate cases with the previous method of functionalization. Énergir believes that a revision of all the rate exhibits affected by this change will be required for the approval of the proposed functionalization method. During the work sessions, there was a discussion with the expert about how the fact of including the previous method might complicate the exhibit. That is why there are no examples of rate exhibits included in this document.

The causality of supply costs is mainly influenced by three factors: average demand, seasonal demand (seasonal surplus usage relative to average demand) and operational flexibility needs.

The current method is based on tool ranking. When the current method was designed, the supply model was rather simple, involving a single supply point and largely relying on one transportation tool. Today, the tool ranking method is no longer entirely appropriate. When developing the supply plan, the goal was to purchase tools to meet the total demand at the lowest cost, without considering the transportation portion. The supply tools were then subsequently ranked from least to most expensive based on the variable cost of use, as long as they could meet daily demand. In reality, the ranking could change any day, depending on the variable cost at that time. An analysis of the impact of the ranking method on the functionalization of costs between transportation and load-balancing is provided in Appendix 3.

A new conceptual framework is now required, as tool ranking no longer necessarily captures cost causality. In fact, the current tool ranking method is not directly based on selecting tools to meet a specific type of demand.

As discussed previously, Énergir had developed the basis of a new conceptual framework in the exhibit B-0133, Gaz Métro-5, Document 1 filed in the case. This new conceptual framework better reflects the modern reality of supply as it includes supply points and types of tools that are being diversified in order to reduce total costs to customers. However, on reading the report from Elenchus Consulting Services, it appears to be possible to clarify the conceptual framework put forward by Énergir and simplify its application.

As such, the new way of implementing the new conceptual framework aims to functionalize the optimized costs of an overall supply plan among the different elements identified during the examination of the cost causality. The newly proposed method is carried out in four steps:

1- <u>Functionalization and classification of transportation costs</u>: Plan and evaluate the cost of supplying the average annual demand using the supply plan tools, given that demand does not fluctuate during the day.

2- <u>Functionalization and classification of seasonal load-balancing costs</u>: Plan and evaluate the cost of supplying the surplus demand relative to the average annual demand using the supply plan tools, given that demand does not fluctuate during the day.

3- <u>Functionalization and classification of load-balancing costs related to operational flexibility</u>: Plan and evaluate the cost of supplying customers for operational flexibility needs using the supply plan tools, considering that demand fluctuates during the day.

4- <u>Functionalization and classification of supply costs not required to meet customer needs for the current year</u>: Identify overage costs related to the supply plan which are not required to meet the supply needs identified in steps 1 to 3.

All of these steps are based on the filed supply plan, as this was the optimal plan at the time of filing. At each step, all existing contracts under this plan can be considered but only those that are useful for meeting the identified needs are retained for each step.

5.1. Step 1: Functionalization and classification of transportation costs

The first step is to simulate a supply plan that meets average annual demand in normal winter conditions. This process will make it possible to determine the portion of supply plan costs to be functionalized to the transportation service.

If the capacity of existing annual transportation contracts were lower than the average annual demand in normal winter conditions, then the cheapest supply tools to meet annual transportation needs would be considered for filling the capacity shortfall. […]

The storage contract with Enbridge Gas at Dawn's physical site could also be taken into account, in the event that Énergir contracted storage capacity in order to reduce annual supply costs and meet average annual demand. As noted in the operational flexibility exhibit filed under the 2018-2019 Rate Case,[36] current economic conditions are unfavourable to the purchase of storage for this purpose. For 2020-2021, no storage capacity at Dawn has been taken into account to meet the average annual demand in normal winter conditions, as this would not be in compliance with the requirement to meet the average demand at the lowest cost.

Excluding supply costs specifically avoided by the potential use of tools such as the storage site in Dawn described in the previous paragraph, the costs of supply are not included in this step. The currently used method of functionalizing supply costs for each rate case (i.e. the application of an annualized price according to a uniform purchase profile during the year) already represents the principle of average demand. Furthermore, although costs are estimated at that time, the functionalization, classification and pricing for the supply are done on a monthly basis and updated every month. Thus, the costs of the rate case do not determine the supply tariff. Lastly, at the end of step 1, given a scenario that includes supply costs, the total costs between supply and transport services would have to be functionalized. For all these reasons, adding the supply

[36] R-4018-2017, Gaz Métro-H, Document 6 (B-0220), Section 2.1.

costs according to a uniform profile would only encumber the methodology and overall calculations in Step 1.

The existing annual transportation sources for 2020-2021 are as follows:

Table 16

Sources[1]	10^3m^3/day	Cost ($000)
Primary FTLH (GMIT EDA & GMIT NDA)[2]	2,243	25,341
Purchases within the territory	8	199
Transportation provided by customers	236	0
FTSH (Dawn-GMIT EDA)	2,192	21,866
Transmission via trade (Dawn-GMIT)	2,875	26,992
FTSH (Parkway-GMIT EDA & NDA)	13,174	125,586
Total transportation capacity	**20,729**	**199,983**

[1] Including all costs related to tools, determined using an LF of 100%.
[2] Including the location differential for natural gas purchases at Empress.

The average demand in a normal temperature scenario is 16,843 10^3m^3/day. It is reasonable to believe that had supply tools always been purchased to meet a uniform average demand over the years, the portfolio of contracts would be approximately the same in terms of proportion. In fact, the variation in the purchase portion would undoubtedly have mirrored the variation in demand over the years, and Énergir would have added the same tools in smaller proportions. Only purchases within the territory and transportation provided by customers would remain at the same level, as these are not influenced by the overall supply structure at this time.

Based on this assumption, the supply structure required to meet the average demand would be as follows:

Table 17

Sources	10^3m^3/day	Cost ($000)
Primary FTLH (GMIT EDA & GMIT NDA)	1,818	20,533
Purchases within the territory	8	199
Transportation provided by customers	236	0
FTSH (Dawn-GMIT EDA)	1,776	17,718
Transmission via trade (Dawn-GMIT)	2,330	21,871
FTSH (Parkway-GMIT EDA & NDA)	10,675	101,760
Total transportation capacity	**16,843**	**162,080**

Functionalized costs for the average annual demand in normal winter conditions for 2020-2021 would amount to $162.1M. These costs can be functionalized to the transportation service, which reflects the average annual demand when using the average demand and surplus method.

5.2. Step 2: Functionalization and classification of seasonal load-balancing costs

The second step is to simulate a supply plan that meets customers' seasonal needs. Seasonal needs are determined based on the tools required to meet peak demand and extreme winter demand. For this step, no fluctuation in demand during the day is considered.

In the 2020-2021 Rate Case, the total supply tools required to meet peak demand exceed those required to meet extreme winter demand. This second theoretical step accordingly incorporates all of the tools contained in Énergir's supply filed plan which are required to meet peak demand.

As in Step 1, the storage contract with Enbridge at Dawn's physical site is not taken into account, as it is not used to reduce annual supply costs for customers. If it were not for operational flexibility needs, Énergir would not need this contract. However, if the additional storage at Dawn were eventually used to reduce supply costs, the portion related to additional storage would be included in this step.

Also, the excess costs of certain tools contracted specifically to meet fluctuations in demand during the day must be deducted. Among the tools held by Énergir, STS contracts may be subject to an additional variable premium under certain conditions, which is not the case for a regular contract between the same trading hubs. Other services,[37] which Énergir may use in the future, also include an additional premium in relation to standard firm tools.

In theory, excess supply costs related to a seasonal purchasing profile could also be placed at this stage. At the time, an a priori estimate of these seasonal costs was included in the tariff case, but this process was abolished for the 2016 tariff case and those thereafter[38]. In short, the application of such an estimate to the tariff cause was imprecise (actual results totally different from projected results) and often led to an increase in year-end variances, resulting in significant fluctuations in the balancing service. As a result, excess supply costs related to an actual seasonal purchase profile are now recognized only at the end of the year (transfer of supply costs to balancing). The actual cost variance thus recognized is then subsequently functionalized in another rate case through a deferred load-balancing charge, and the counterpart affects the next natural gas price in the shorter term.

Based on past contracts and the projected optimization in the 2020-2021 Rate Case, the supply plan tools required to meet peak demand are as follows:

[37] For example, the TCE Enhanced Market Balancing (EMB) service provides 8 nomination windows per day.

[38] See paragraph 79 of decision D-2015-177, where the Régie deems it appropriate to use a method of summary functionalization in the rate file, excluding actual seasonal costs, which are dealt with specifically in the annual report using more representative actual data.

Table 18

Sources[1]	10^3m^3/day	Cost ($000)
Primary FTLH (GMIT EDA & GMIT NDA)	2,243	25,341
Purchases within the territory	8	199
Transportation provided by customers	236	0
FTSH (Dawn-GMIT EDA)	2,192	21,866
Transmission via trade (Dawn-GMIT)	2,875	26,992
FTSH (Parkway-GMIT EDA & NDA)	13,174	120,716
STS (Parkway-GMIT EDA & NDA)	5,705	50,598
Pointe-du-Lac	1,600	6,108
Saint-Flavien	1,512	12,903
Interruptible offering (super interruptible)	1,586[39]	396[40]
Peak service	1,074	108
LSR plant (vaporization)	5,806	8,466
Liquefaction interruptions, GM LNG	297	0
Total supply tools	**38,309**	**273,693**

1) Including all costs related to tools, determined based on the projected use of the tools, and excluding the return on the rate base and taxes.

The total cost of the supply tools is $273.7M. In order to calculate the specific costs of customers' seasonal load-balancing needs, the $162.1M in costs that were functionalized to average demand and classified under the transportation service must be deducted. As a result, specific costs of $111.6M can be functionalized to customers' seasonal needs. These costs can be classified as seasonal load-balancing costs.

It should be noted that even if extreme winter demand had exceeded peak demand, the process could still have been carried out in the same way.

[39] For the purposes of the functionalization process, all interruptible volumes, determined based on the interest shown by customers in an interruptible option (see exhibit Gaz Métro-5, Document 13, Section 7.3, Table 7, l. 4, col. 1), are considered to have migrated to the continuous service under the peak interruptible offering. The Daily Interruptible Volume (DVI) of 1,586 10^3m^3 has therefore been added to the peak of 36,723 10^3m^3 used for the 2020–2021.

[40] Cost estimated based on the assumption provided in the note on the previous page: DVI of 1,586 10^3m^3/day multiplied by a fixed credit of $0.25/m³ corresponding to the peak interruptible offering. No variable credit payments are anticipated, which means that no interruptions have been projected.

5.3. STEP 3: FUNCTIONALIZATION AND CLASSIFICATION OF LOAD-BALANCING COSTS RELATED TO OPERATIONAL FLEXIBILITY

From the outset, it should be noted that the exhibits B-0184, Gaz Métro-5, Document 4 and B-0187, Gaz Métro-5, Document 6, which were filed in the case as follow-ups to previous decisions, are no longer valid in the current context. The following paragraphs identify and explain operational flexibility needs and the costs required to meet them within the current supply context at Énergir, which includes the now-completed move to Dawn.

The third step consists of adding the costs of tools that have been added to the supply plan, in addition to the tools required to meet seasonal load-balancing and transport needs, to meet needs related to the fluctuation in demand during the day. The additional needs related to the fluctuation in demand during the day reflect operational flexibility needs.

The type of tools used to perform this specific function are not geared toward meeting peak demand or extreme winter demand. Typically, these tools make it possible to adjust nominations during the day using nomination windows available throughout the gas day.

Énergir mainly uses two tools to meet this type of need: supply storage at Dawn's physical site and STS transportation contracts. These two tools add nomination windows to the nomination windows already available through the basic transportation tools.

For the time being, Énergir only contracts storage capacity at Dawn in relation to operational flexibility needs.[41] That means that all costs related to storage at Dawn are included in this step. For this reason, Énergir is able to forecast the decrease in supply costs resulting from the use of the Dawn storage facility. These supply savings are implicitly included in the plan, which uses storage at Dawn as an operational flexibility tool. The supply savings result from the supply price differential, which is based on the NGX Dawn index between the time of injections and the time of withdrawals.

STS transportation contracts also serve to meet the seasonal needs of customers. Since the costs of a basic transportation contract are already taken into consideration when functionalizing the cost of customers' seasonal needs, only the excess costs in relation to basic costs are taken into account with regard to operational flexibility. In the 2020-2021 Rate Case, no excess costs related

[41] A profitability analysis with regard to contracting storage capacity at Dawn, and which also takes projected supply costs into account, is carried out when each rate case is drawn up (see R-4119-2020, B-0116, Énergir-H, Document 2).

to the use of this type of contract are projected, as, during its normal operations, Énergir generates credits that offset any additional cost of the STS.

Based on the contracts in effect for the 2020-2021 Rate Case and the projected monthly supply prices, the following table illustrates the projected costs for the tools required to meet needs related to the fluctuation in demand during the day:

Table 19

Sources(1)	Cost ($000)
Storage at Dawn	11,315
Decrease in supply costs	-5,200
STS (Parkway-GMIT EDA & NDA)	0
Cost of operational flexibility	**6,115**

(1) Excluding tax and the return on the rate base

The costs incurred for the tools required to meet operational flexibility needs amount to $6.1M and can be functionalized and classified as load-balancing costs related to operational flexibility.

5.4. Step 4: Functionalization and classification of supply costs not required to meet customer needs for the current year

The fourth and final step is to evaluate the supply costs not required to meet customer needs for the current year.

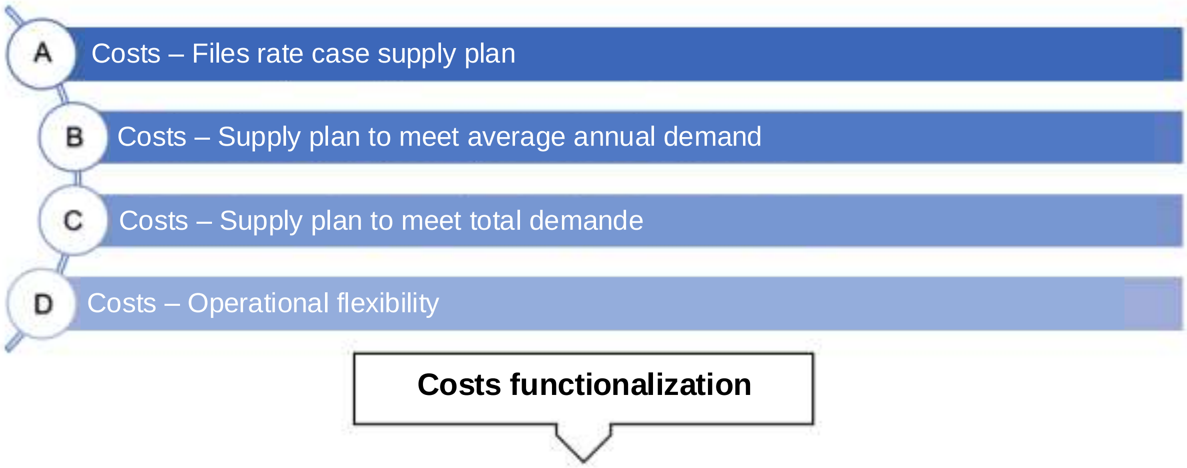
It may not be possible to terminate existing supply contracts in the short term, even if they are not required to meet customer needs (average demand, seasonal demand or operational flexibility). The remaining costs related to these contracts which were not functionalized in the first three steps would therefore be part of the fourth step.

Normally, these costs would come from a surplus of transportation tools sold at a profit or loss, referred to in Section 2.1.5 as stranded costs unrelated to temperature. The result of the net costs of revenue from sales would then be functionalized to the load-balancing service under the category "Supply costs not required to meet customer needs for the current year."

No costs or revenue of this nature were projected in the 2020-2021 Rate Case.

Cost functionalization using the three-tier method can be summarized as follows:

Diagram 1



Transportation	Seasonal load-balancing	Operational flexibility load-balancing	Load-balancing not required
B	C - B	D	A – (C + D)

5.5. DETERMINATION OF TRANSPORTATION AND LOAD-BALANCING COSTS AND DETERMINATION OF REQUIRED REVENUE

Once the various supply costs between transportation and load-balancing services are functionalized via the previous four steps, it is necessary to add other cost elements and make certain adjustments in order to determine the required revenue to be recovered from the rates charged to customers for the various services.

The adjustments and additional cost elements to be taken into account for the transportation service are as follows:

- Calculation of the transportation cost associated with gas used for operations and lost gas to be reclassified under the distribution service;
- Calculation of the transportation cost for competitive make-up gas (CMUG) transported by Énergir;
- Addition of the annual cost of the Champion Pipeline. Following decision D-2020-047, the Régie ordered that this cost be fully functionalized to the transportation service. Énergir

adds the cost at this stage rather than including it in the step 1, to prevent it from being partially functionalized to load-balancing.

The following table illustrates the integration of these three elements into the results of the tables from steps 1 to 4 (sections 5.1 to 5.4). Line 5 of the following table shows the amounts that will be included in line 1 "Transportation, load-balancing, CATS and distribution expenses" of the Required Revenue exhibit of the rate case (R-4119-2020, Énergir-N, Document 1, page 1).

Table 20
Determination of costs by service **($000)**

	(1)	Transportation *(2)*	Seasonal load-balancing *(3)*	Load-balancing – Operational flexibility *(4)*	Load-balancing not required *(5)*	Total *(6)*
1	**Results from Tables 17 to 19**	162,080	111,613	6,115	0	279,808
2	**Other cost elements** ***Gas used in operations and lost gas***	(3,084)	0	0	0	(3,084)
3	***Competitive make-up gas***	379	0	0	0	379
4	***Transportation – Champion Pipeline***	4,806	0	0	0	4,806
5	**Transportation and load-balancing expenses**	**164,181**	**111,613**	**6,115**	**0**	**281,909**

Once the basic transportation and load-balancing expenses have been determined, income taxes and the return on the rate base must be allocated among the services. As explained in Section 2.3.2, the purpose of maintaining inventories is to serve the needs of customers with seasonal profiles. Costs related to supply and transportation inventories must therefore be allocated according to the seasonal consumption profile. As a result, income taxes and the return related to maintaining inventories are allocated to seasonal load-balancing.

The required revenue resulting from this second set of adjustments is illustrated in […] table 21-A:

Table 21-A **($000)**

			Step 1	Step 2	Step 3	Step 4	
	(1)	Supply *(2)*	Transportation *(3)*	Seasonal load-balancing *(4)*	Load-balancing – Operational flexibility *(5)*	Load-balancing not required *(6)*	Total *(7)*
1	**Transportation and load-balancing expenses**	0	164,181	111,613	6,115	0	281,909
2	***Amortization of fixed assets***	0	0	1,477	0	0	1,477
3	***Amortization of deferred charges and intangible assets***	0	(20,798)	13,494	0	0	(7,304)
4	***Income tax***	0	537	1,162	134	0	1,833
5	***Return on rate base***	0	(475)	6,487	903	0	6,916
6	**Required revenue before recharge to the GM LNG customer for use of the LSR plant**	0	143,445	134,233	7,153	0	284,832
7	***Cost of using the LSR plant reimbursed by the GM LNG customer***	0	0	(4,895)	0	0	(4,895)
8	**Required revenue from regulated customers**	**0**	**143,445**	**129,338**	**7,153**	**0**	**279,937**

1 Table 21-B presents the required revenue as originally filed as part of the file R-4119-2020 at
2 Exhibit B-0168, Énergir-N, Document 1, page 1. Table 21-C shows the differences resulting from
3 the application of the new functionalization method for each of the required revenue components.

Table 1-B **($000)**

	Required revenue filed (R-4119-2020) *(1)*	Supply *(2)*	Transport *(3)*	Peak Balancing *(4)*	Space Balancing *(5)*	Total *(6)*
1	**Transport and balancing costs**	0	163,734	54,817	56,048	274,599
2	***Fixed asset amortizations***	0	0	1,477	0	1,477
3	***Amortization of deferred charges and intangible assets***	0	(20,798)	0	13,494	(7,304)
4	***Income tax***	268	481	797	288	1 833
5	***Return on rate base***	1,812	(258)	3,655	1,706	6,916
6	**Required revenue before recharge to the GM LNG customer for use of the LSR plant**	2,080	143,159	60,746	71,536	277,521
7	***Cost of using the LSR plant reimbursed by the customer GM LNG***	0	0	(4,895)	0	(4,895)
8	**Required revenue from regulated customers**	**2,080**	**143,159**	**55,851**	**71,536**	**272,626**

Table 21-C ($000)

	Differences between the required revenue under the proposed method and the required revenue filed (1)	Supply (2)	Step 1 Transport (3)	Step 2 Seasonal load-balancing (4)	Step 3 Load-balancing – Operational flexibility (5)	Step 4 Load-balancing Not required (6)	Total (7)
	Calculation reference in tables 21-A and 21-B	21-A col. 2 – 21-B col. 2	21-A col. 3 – 21-B col. 3	21-A col. 4 – 21-B col. 4 and col. 5	21-A col. 6	21-A col. 7	21-A col. 8 – 21-B col. 6
1	**Transport and balancing costs**	0	447	749	6,115	0	7,311
2	***Fixed asset amortizations***	0	0	0	0	0	0
3	***Amortization of deferred charges and intangible assets***	0	0	0	0	0	0
4	***Income tax***	(268)	56	77	134	0	0
5	***Return on rate base***	(1,812)	(217)	1,126	903	0	0
6	**Required revenue before recharge to the GM LNG customer for use of the LSR plant**	(2,080)	286	1,126	7,153	0	7,311
7	***Cost of using the LSR plant reimbursed by the customer GM LNG***	0	0	0	0	0	0
8	**Required revenue from regulated customers**	**(2,080)**	**286**	**1,952**	**7,153**	**0**	**7,311**

Considering the application of the new functionalization method, the required revenue […] is $279.9M, […] meaning $7.3M more than the originally filed required revenue of $272.6M[42]. This increase is mainly due to the net effect of the following items.

First, the $7.3M increase in transmission and load-balancing costs (Table 21-C, line 1), affecting mainly seasonal load-balancing and operational flexibility services, is the net result of the following two items:

(i) The proposal to eliminate the deferred expense accounts for transportation tools functionalized to load-balancing (see explanation below) means that the twelve existing

[42] R-4119-2020, B-0168, Énergir-N, Document 1, page 1, l. 14, col. 4+5+6.

fixed premiums for the fiscal year would be charged directly to income, rather than being posted to the DEA, which would increase service costs by $12.7M. It should be noted that for the purpose of simplifying the simulation, the decrease in the cost of return and income taxes, as well as the amortization of the DEA balance projected as at October 1, 2020 (balance deferring the fixed premiums paid for the months of April to September 2020) have not been included.

(ii) On the other hand, the $5.2M supply savings resulting from storage at Dawn translate to a decrease in the cost of operational flexibility, as explained in Section 5.3.

In addition, as discussed in Section 2.3.2 of this document, in order to allocate the costs of maintenance of inventories on a causal basis, it is necessary to reclassify them to seasonal load balancing and operational flexibility services, since currently the largest proportion of the value of inventories is allocated to the supply service. This reclassification therefore results in an upward effect on revenues from seasonal load-balancing and operational flexibility services, while conversely, supply service revenues are reduced. It should be noted that this reclassification of taxes and return has a nil effect in terms of change in total required revenue, as presented in lines 4 and 5 of Table 21-C.

[…]

<u>Elimination of the Deferred Expense Account (DEA) related to the fixed premiums for the Dawn storage site and for transportation tools functionalized to load-balancing</u>

IMPORTANT

The elimination of this DEA was not included in the initial proposal made in the case.

Énergir is proposing to eliminate the DEA combining the fixed premiums for the Dawn storage site and for transportation tools functionalized to load-balancing. This DEA has been in use since decision G-361 was handed down by the Régie on January 18, 1984. However, the way the Dawn storage site is used has evolved since it was created.

In the past, Énergir purchased little or no commodity at Dawn to fill the Dawn storage site. The site was mainly used to meet two objectives: maximizing FTLH transportation capacity and meeting load-balancing demand in winter. The transportation tools functionalized to load-balancing were therefore primarily used to supply the storage site in the summer (April to September) in preparation for its use in the winter of the following fiscal year (October to March). As a result, the method still in use today defers to the next fiscal year the full cost of the fixed premiums for the Dawn storage site and the cost of transportation tools functionalized to load-balancing for the six previous months of the fiscal year, in order to amortize these costs over the period of use of the site for the following October to March. This method made it possible to align the amortization of the DEA with the period of withdrawal from the storage site.

Over the years, Énergir's supply structure has evolved and the commodity is now primarily purchased from Dawn. Furthermore, as explained in this case, the Dawn storage site is now being used for operational flexibility. This means that the logic on which the DEA was based — reconciling the costs of the injection and withdrawal periods — is no longer valid. As a result, Énergir proposes to eliminate the DEA related to the fixed premiums for the Dawn storage site and for transportation tools functionalized to load-balancing.

The impacts of eliminating the DEA are as follows:

1- Permanent decrease of the rate base for load-balancing. According to the data in the 2020-2021 Rate Case, this decrease would amount to $30.9M, resulting in a $1.9M decrease in the return on the rate base and income taxes.

2- One-time increase in load-balancing costs during the year the DEA is eliminated. According to the data in the 2020-2021 Rate Case, this increase would amount to $35.8M. This amount represents the deferral of costs for the six months of the fiscal year preceding the elimination of the DEA. In fact, in the first fiscal year during which the DEA is eliminated, all fixed expenses for the twelve months of that fiscal year will be recorded in income, in addition to the amortization of the DEA carried forward from the previous year. In this regard, in order to limit the rate shock that would result from the addition of such an amount to the load-balancing costs for a single fiscal year, Énergir proposes that the Régie amortize the $35.8M cost over a longer period, which remains to be determined.

In this exhibit, considering how the supply structure and the use of the Dawn storage site has evolved, Énergir recommends that the DEA be eliminated.

It should be noted that the impacts listed above with regard to eliminating the DEA were not taken into account in the simulation of required revenue discussed earlier. As such, the simulation does not reflect the $1.9M decrease in the cost of return and income taxes, nor does it reflect the full or partial amortization of the projected $35.8M DEA balance as at October 1, 2020.

6. FUNCTIONALIZATION AND CLASSIFICATION OF COSTS RELATED TO VARIANCES RECORDED IN THE ANNUAL REPORT

IMPORTANT

As in Section 5, since the following section concerns the functionalization method, it should be noted that the functionalization method applied in this exhibit is different from the one originally proposed by Énergir. The proposed method for processing overpayments and shortfalls has been added as per the recommendations of Elenchus Consulting Services.

When the rate case is filed, revenues are perfectly balanced with costs. At year end, however, variances between revenue and costs can be observed. These variances are then charged to DEAs as overpayments or shortfalls to be included in the service cost of a future rate case. It is important to functionalize these variances among services according to their causal links.

6.1. ADJUSTMENTS TO THE ANNUAL REPORT – CURRENT METHOD

At year end, supply purchases are functionalized among the supply, transportation and load-balancing services.[43] This compensates for the fact that some of the costs included in the rate case are influenced by the seasonal needs of Énergir's customers and that Énergir purchases supply at locations other than the Dawn reference point. At year end, the costs related to seasonal supply purchases are correspondingly transferred to load-balancing. A seasonal cost is also included in the costs functionalized to the transportation service, which are related to supply purchases made at locations other than the reference point. This seasonal cost results in a transfer from transportation to load-balancing.

These cost transfers among services are captured by the overpayments or shortfalls of each service at the end of the fiscal year.

[43] Please refer to the example in exhibit B-0044, Énergir-9, Document 2, pages 5 and 6 of case R-4114-2019.

The new step-by-step cost functionalization method requires a review of year-end adjustments. This will ensure that costs can be recovered through the functions of the following rate cases.

6.2. ADJUSTMENTS TO THE ANNUAL REPORT – PROPOSED STEP-BY-STEP METHOD

The proposed cost functionalization method is carried out in steps. At each step, the various tools of the supply plan are functionalized according to the type of need they meet.[44] For proper functionalization of costs among services for the annual report, there is more to consider than simply functionalizing supply purchases among the supply, transportation and load-balancing services.

Three types of adjustments are required at year end:

1- Adjustments entailed in updating the supply plan tools at the beginning of the rate year;

2- Adjustments entailed in updating the actual costs of the supply plan tools;

3- Adjustments entailed in seasonal needs.

6.2.1. Adjustments entailed in updating the supply plan tools at the beginning of the rate year

The first type of adjustment is related to updating the supply plan at the beginning of the year. It is important to note that this type of adjustment is only required when significant changes in demand call for changes to be made to the purchase or sale of transportation or storage tools at the beginning of the year in comparison to the projection in the rate case. For example, this situation could arise if a large customer were unexpectedly added or withdrawn between the time the rate case was drawn up and the moment when Énergir reassessed demand at the beginning of the year. In more rare instances, a sudden change in the economic context could result in a change in consumption by a group of customers large enough for adjustments to the supply plan to be required.

These adjustments to the supply plan would then result in changes to cost functionalization, in relation to what was established in the rate case, which would need to be reflected in year-end results. For the purposes of preparing the annual report, Énergir

[44] Transportation, seasonal load-balancing, operational flexibility and "not required."

proposes to update steps 1 to 4 in order to take the tools of the current supply plan into consideration, based on the demand reassessed at the beginning of the year.

6.2.2. Adjustments entailed in updating the actual costs of the supply plan tools

The second type of adjustment is related to updating the actual costs of the supply plan tools. There are several costs that may vary during the year: transportation tool rates, the location differential for purchases at points other than the supply reference point, the compression ratio throughout the year, storage tool rates, etc. It is necessary to update the actual costs in order to properly functionalize the costs between the different services.

These adjustments must be made individually for steps 1 to 4 according to the forecast plans for each of them.

6.2.3. Additional adjustments entailed in seasonal needs

The last type of adjustment is related to seasonal needs. There are three situations related to seasonal needs which may lead to variances at year end.

a) Transfer of variances related to seasonal consumption from the transportation service to seasonal load-balancing

At year end, Énergir currently evaluates the transfer of load-balancing costs included in transportation[45] as per decision D-2015-177. By making the adjustments described in sections 6.2.1 and 6.2.2, costs would be functionalized to the transportation service based on average demand during normal winter conditions, eliminating any seasonal effect on costs. As a result, Énergir proposes to stop calculating the load-balancing cost included in transportation as is currently done, because it would no longer be necessary.

However, an adjustment must still be made to prevent any variance caused by a seasonal effect in the transportation service at the end of the fiscal year. As long as a customer’s consumption is stable (i.e. LF of 100%), average demand remains the same regardless of whether the winter is warm or cold. On the other hand, the demand of customers with seasonal needs varies when winter conditions differ from normal

[45] Example of calculation in exhibit B-0044, Énergir-9, Document 2, p. 4, l. 6 and 7 of case R-4114-2019.

temperatures. Therefore, the actual consumption of such customers results in a variance at year end, which essentially translates to a variance in transportation revenue directly linked to their consumption profile. In addition, as demonstrated in Section 4, the transportation and storage costs in the supply plan vary very little when winter temperatures are warmer or colder than usual. As a result, this situation creates an imbalance between the revenue recorded in the transportation service to reflect the seasonal profile of customers and the costs corresponding to a uniform consumption profile.

To correct this imbalance, Énergir proposes to make an adjustment based on distribution volume normalization. In order to calculate the variance at year end, transportation revenue would be adjusted based on the normalized volume recorded during the fiscal year and the other part of this adjustment would be recorded in the seasonal load-balancing service. That way, no variance related to the seasonal profile of customers would be recorded in the transportation service.

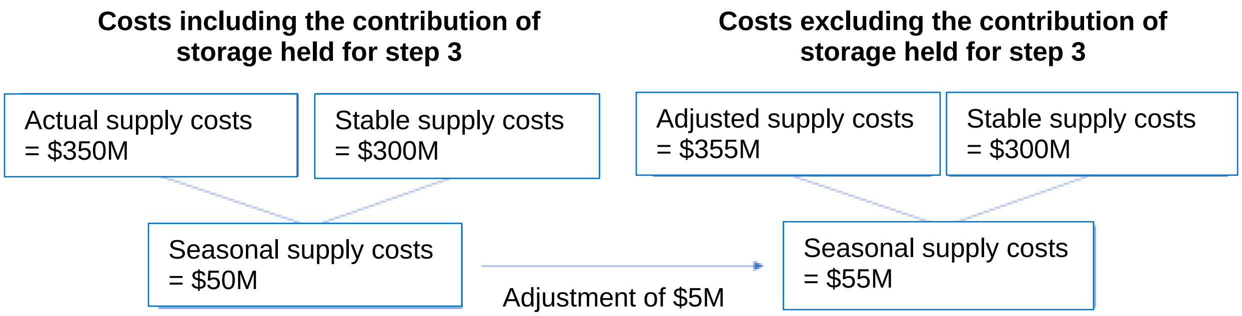
b) <u>Transfer of seasonal costs from supply to seasonal load-balancing</u>

In keeping with the principle of uniform delivery, the supply price should be free from seasonal effects. This price should therefore be equal to the price that a customer with a completely stable profile would pay to purchase supply from the reference point. For this reason, an adjustment related to the seasonal supply cost must be made. Énergir is proposing a new method for calculating the transfer of supply costs to seasonal load-balancing, as outlined in Appendix 5.

c) <u>Adjustment related to calculating the supply savings resulting from operational flexibility needs affecting seasonal load-balancing</u>

When the annual report is drawn up, the supply cost savings resulting from operational flexibility needs will be updated based on the actual parameters. An additional adjustment related to seasonal supply costs is then required after re-evaluating these savings. In fact, as mentioned in Section 5.3, the costs incurred to meet operational flexibility needs are tied to storage quantities that make it possible to reduce supply purchase costs. That means that the storage capacity contracted for operational flexibility purposes reduces the seasonal cost previously discussed under item b). The cost variance arising from the use of storage must therefore be adjusted for seasonal supply costs to bring the value of the transfer of supply costs to seasonal load-balancing to what it would have been if Énergir did not own the storage site allowing for operational flexibility. The following diagram illustrates this adjustment:

Diagram 2



6.2.4. Functionalization and classification of year-end variances

These various adjustments will make it possible to identify the year-end variances[46] representing the overpayments/shortfalls for each service. They will be charged to DEAs to be remitted to/recovered from customers in subsequent rate cases.

7. COST ALLOCATION

Once all costs have been functionalized by service and segmented and classified under the corresponding cost item, they should be allocated by customer category according to the allocation factors determined based on the strongest possible causal links. It should be noted that Section 7 contains several follow-ups of decisions made by the Régie over the years, since the beginning of the case.

In decision D-2016-126, the Régie also asked Énergir to explain in what way the complementarity or non-complementarity of the consumption profiles impacts the economies of scale and their distribution among the customers:

> "*[65] The distributor should also specify in what way the complementarity or non-complementarity of the consumption profiles of the different customer categories impacts:*

[46] Variance between revenues and costs after adjustments.

- *The economies or diseconomies of scale associated with the costs of the tools retained in the plan;*
- *Their distribution among the different customer categories.*" [Translation]

In Section 7.1, Énergir provides an update on the theoretical concepts developed to address the Régie's request for clarification on paragraph 65. Next, the allocation factors used to allocate costs under the proposed method are explained in Section 7.2. Appendix 7 also contains additional follow-ups related to the Régie's requests following the filing of Énergir's initial exhibit.

7.1. JUSTIFICATIONS FOR THE ASSUMPTIONS MADE

Before allocating costs by customer, some of the underlying concepts should be reviewed in order to demonstrate how the complementarity of the consumption profiles impacts the economies of scale and their distribution.

7.1.1. Effect of temperature on consumption and cost allocation

Under the current method, the costs functionalized to transportation and load-balancing are mostly unaffected by the actual observed temperature. The functionalization exercise is carried out at the start of the year based on the projected volume for a normal temperature. Then, depending on the winter observed, a difference in the projected volume will create overpayments or shortfalls that will be returned to the customers via the transportation and load-balancing services. Since the functionalization is never reviewed at year-end, the allocation is never a function of the actual temperature.

In the proposed method, the costs functionalized to transportation and load-balancing are affected by the observed temperature. Standardization based on excess or deficit volumes related to the observed temperature is proposed in order to adjust revenues and correct the year-end difference between transmission and load-balancing services.[47] So, the functionalization adjusts automatically according to whether the perceived temperature is warmer or colder.

[47] On this topic, see section 6.2.3. a).

It is thus at the functionalization stage that the temperature's impact can be captured and not at the cost allocation stage since the method of allocating the costs does not influence the total costs to be allocated to transportation and load-balancing.

7.1.2. Relativity of the consumption profiles based on the temperature

In reviewing customers' overall consumption for the years 2010 through 2014, the most important factor noted for the variation in customer consumption is the temperature. For these years, a correlation coefficient R^2 of 0.93 to 0.96 was observed (maximum 1)[48] between the demand and the degree-days without taking into account any other factor (working days and non-working days, wind or temperature of the previous day).

Since the daily variation in customers' consumption results almost entirely from the variation in the temperature, it is possible to consider that the customers' consumption profiles are all interrelated based on their CU.

To illustrate this point, here are three different consumption profiles based on normal temperatures.

Table 22

	A	W	P	W-A variance	P-W variance	P-A variance	W-A variance	P-W variance	P-A variance
	(units)	*(units)*	*(units)*	*(units)*	*(units)*	*(units)*	*(%)*	*(%)*	*(%)*
Customer 1	100	180	300	80	120	200	62	71	67
Customer 2	100	150	200	50	50	100	38	29	33
Customer 3	100	100	100	0	0	0	0	0	0
Total	**300**	**430**	**600**	**130**	**170**	**300**	**100**	**100**	**100**

Based on the relativity of the consumption profiles, if the temperature is colder than normal, customer 1's consumption will increase more than that of customer 2, whereas customer 3's consumption will not change.

[48] Appendix 1, graphs 1.3 to 1.7.

Table 23

	A	W	P	W-A variance	P-W variance	P-A variance	W-A variance	P-W variance	P-A variance
	(units)	*(units)*	*(units)*	*(units)*	*(units)*	*(units)*	*(%)*	*(%)*	*(%)*
Customer 1	126	201	300	75	99	174	62	71	67
Customer 2	114	160	200	46	40	86	38	29	33
Customer 3	100	100	100	0	0	0	0	0	0
Total	**340**	**461**	**600**	**121**	**139**	**260**	**100**	**100**	**100**

1 The effect is reversed when the temperature is warmer. Customer 1 will reduce its
2 consumption more than customer 2's. And once again, customer 3's consumption will
3 remain the same.

Table 24

	A	W	P	W-A variance	P-W variance	P-A variance	W-A variance	P-W variance	P-A variance
	(units)	*(units)*	*(units)*	*(units)*	*(units)*	*(units)*	*(%)*	*(%)*	*(%)*
Customer 1	78	163	300	85	137	222	62	71	67
Customer 2	92	144	200	52	56	108	38	29	33
Customer 3	100	100	100	0	0	0	0	0	0
Total	**270**	**407**	**600**	**137**	**193**	**330**	**100**	**100**	**100**

4 Although the preceding examples present only one variation in the overall winter
5 temperature, variation of the peak would provide the same results: the relative relationship
6 of the profiles (defined by parameters A, W et P) always remains the same.

7.1.3. Calculation of individual and overall customer consumption

7 To establish the supply plan, it is not useful to calculate each customer's actual or
8 projected consumption amounts, except in the case of certain major gas consumers. This
9 is mainly owing to the fact that the overall consumption of all customers depends almost

entirely on the variation of the temperature. So, using total daily consumption data to build the supply plan makes it possible to obtain adequate projection scenarios.

The supply plans, whether for warm winter, cold winter, extreme winter or the peak period, cannot be directly divided among the customers since they are calculated globally and not per customer.

If individual calculations were done, the total projected peak obtained would be higher. Indeed, the calculations are based on historical data. However, the coldest day can be different in each region for a given year. Furthermore, depending on whether the peak is a working day or a non-working day, each customer's individual peak may not occur on the same day either. The result is that the non-coincident peak of customers is always higher than the coincident peak.

The difference between each customer's individual peak and the calculated overall customer peak represents the economies of scale related to an overall planning of the supply for all of the customers instead of for each individual customer. Indeed, if customers each provided their own supply, they would each have to cover their own peak, regardless of whether or not it coincided with that of the other customers. By calculating a peak for all of the customers, the distributor is achieving savings that benefit all customers that have a peak during the winter. The economies of scale are therefore related to the complementarity of the customers' delivery profiles.

7.1.4. Distribution of the economies of scale

The elements presented allow for the following conclusions:

- Since the economies of scale are related to the complementarity of the consumption profiles (section 7.1.3), they should therefore be allocated based on these profiles.

- For this to occur, the economies of scale must be completely functionalized to the load-balancing service.[49] In section 7.1.1, it was mentioned that the proposed method for functionalizing the costs takes into account the effect of the

[49] If the economies of scale were instead functionalized to transportation, the allocation would be done according to the customers' volume and not their profile.

temperature and the actual volumes consumed: the economies of scale are thus automatically in load-balancing.

- The allocation of the costs functionalized to the load-balancing service is done according to the particular profile of the customers in each rate class. Given the relativity of the profiles (section 7.1.2), the economies of scale will be distributed fairly among the rate classes.

So, using the consumption profile of each rate class enables a precise distribution of the economies of scale.

7.1.5. Allocation of the costs for customers with interruptible service

To allocate the costs to interruptible customers, it first must be determined how the interruptible service's value will be recognized. On the one hand, interruptible-service customers can be seen as regular customers who make Énergir a value proposition. On the other, interruptible customers can be seen as customers who receive an inferior service delivery for which a reduction of the costs (and subsequently the rate) is required.

As explained in the exhibit on re-engineering the interruptible service (Gaz Métro-5, Document 13), the interruptible volumes can be considered a supply source that enables it to limit the costs by limiting the surplus annual transportation tools that need to be contracted. From this perspective, the interruptible offer is a value proposition. In fact, Énergir can make use of other supply options on the market to which the interruptible offer must be compared. For example, Énergir could find tools that would result in the interruptible customers not providing it with any value and therefore not being of use. In addition, the interruptible offer must provide a benefit to the other customers: otherwise, it amounts to not having an optimal supply plan for the continuous customers.

The value proposition model was also validated during a customer survey: customers prefer significant variable premiums to more modest fixed premiums[50]. Although the existing cost and rate reduction model for distribution results in greater savings than those

[50] Most of the customers surveyed expressed a greater interest in an interruptible model that provides a very substantial financial advantage only when there are interruptions. On this topic, see Section 6.2.2 of exhibit Gaz Métro-5, Document 13.

achieved by reducing the use of peak tools, it is not attractive to the interruptible customers, who are migrating to the continuous service a bit more every year.

Moreover, the contribution of the interruptible customers lies in the reduction of the annual transportation tools to meet the peak. This cost reduction does not depend on the number of days of interruption required. Indeed, if interruptible customers make it possible to reduce the transportation tools required by 10,000 m^3/day and an equal distribution of the savings among the interruptible- and continuous-service customers is targeted, then the value will always be *10,000 ^{3}/day x 50% x Annual transportation cost*, regardless of the number of days of interruption projected.

So, for the interruptible service to provide greater value to both interruptible and continuous customers, the contribution associated with the interruptible offering must be considered a supply cost, the same as the other tools purchased to serve the peak demand. This cost should be allocated to all customers, in the same manner as the supply tools.

At present, allocation of the load-balancing costs to the interruptible service is done by modifying the A, W and P parameters based on the number of days of interruption.[51] This inferior allocation is a result of the fact that the interruptible service is currently viewed as a lower quality service. As the interruptible service is now viewed as a supply “tool,” the allocation of costs to the interruptible service must be based on the actual consumption profile and thus unmodified parameters.

7.2. COST ALLOCATION FACTORS

The index of allocation factors for supply, transportation and load-balancing costs is provided in Appendix 6. This appendix was used to compile the results of the cost allocation studies carried out by comparing the current methods and rates to the proposed methods and rates, provided in exhibit Gaz Métro-5, Document 14. In order to fully understand the changes made by Énergir in

[51] Exhibit R-3559-2005, SCGM-12, Document 11, Section 2.

this index, it would be useful to further explain the cost causality underlying the proposed allocation factors.

IMPORTANT

As a whole, the proposal concerning the cost allocation factors remains the same as the one originally filed in this case. The differences are as follows:

- **Minor changes to the rate base in supply and transportation;**
- **Allocation of Champion transportation costs.**

7.2.1. Supply

Supply service costs should be free of seasonal effect, meaning that the costs that should remain in the supply service are only those costs linked to supplying a theoretical profile with an LF of 100%.

However, in the current allocation method, some seasonal costs are allocated to supply. In fact, inventory-related costs are also included (value of the supply in the storage sites with taxes and return). In the proposed method, Énergir demonstrated that inventory costs are related to the load-balancing needs of all customers, not only related to customers of the distributor's supply service.[52] Inventory-related costs meeting the need for intra-day operational flexibility, with the exception of storage at Dawn, are generated by all customers with a seasonal consumption profile. Since Énergir is proposing to functionalize these costs to the load-balancing service, the elements that currently make up the rate base for the supply service, such as regulatory cash balances and inventory, would now be included in the rate base for the load-balancing service. As a result, the amount incurred to maintain supply inventory, with the exception of maintenance related to storage at Dawn, would be functionalized to load-balancing under the "Seasonal load-balancing" line item.

[52] See sections 2.2.7 and 2.3.2.

This new method of functionalizing inventory costs would ensure that no costs related to income tax or the return on the rate base would be allocated to supply (net supply revenue would become zero for all customers).

7.2.2. Transportation

Transportation service costs must match all of the costs incurred to meet the theoretical needs of customers with an LF of 100% (i.e. with equivalent stable demand). Like supply costs, transportation costs must therefore be adjusted for seasonal effect to reflect the costs of the transportation market serving customers with totally stable demand.

Once again, under the current allocation method, some seasonal costs are allocated to transportation, in seasonal costs related to transportation inventory. However, in line with the process for supply, Énergir proposes to functionalize these costs to load-balancing under the “Seasonal load-balancing” item.

For regulatory cash balances, Énergir proposes to use transportation service volumes. This cost is evaluated at the time the rate case is drawn up and is based on the transportation cost projected in the budget and the differential between the average time to recover revenue and the average time to pay suppliers (net lag). As the proposed transportation costs are directly and continuously determined based on the volumes consumed by customers in compliance with the principle of average demand, transportation service volumes provide the best causal link.

The “Unamortized cost” item of the rate base represents the various deferred expenses attributed to the transportation service. As the transportation service must be completely free of seasonal effect, any deferred expenses that would remain in the transportation service under the proposed method (such as overpayments or shortfalls) cannot have a seasonal effect. For this reason, Énergir proposes to use the transportation service volume rather than the variance between average winter consumption and average annual consumption to allocate these costs, as is the case with the current method.

Transportation costs are currently allocated according to the transportation service volume (FB01T), excluding income tax (according to REVNETT) and the return on the rate base (BASETART). Énergir proposes to allocate the costs in the same way as is currently done, except when it comes to income tax, competitive make-up gas (CMUG) and the Champion Pipeline (Champion). As Énergir is proposing to charge a transportation cost that is completely free of seasonal effect, income tax costs would instead be allocated according to the transportation service volume. For CMUG, Énergir proposes an allocation only to customers that consumed CMUG. This direct allocation means that CMUG revenue and costs would be separate from total transportation revenue and costs. Énergir's proposal with respect to Champion costs is provided in Section 7.2.3.

The "Annual transportation tools" item is an abridged representation of the total number of tools available in Section 5.1 (Table 16) in addition to *Gas used in operations* from Section 5.5 (Table 20, Column 2, Line 2).This item includes all costs that can be functionalized to the transportation service which, according to the three-tier method, reflect the average annual demand (with the exception of CMUG and Champion). Énergir proposes to allocate these costs according to transportation service volumes, which would ensure compliance with the principle of average demand and surplus at all times.

7.2.3. Allocation of Champion costs for customers who procure their supply from the franchise

In decision D-2020-047[53] regarding phase 2A of the file, the Régie asked Énergir and the stakeholders to bring forward the issues that should be examined in connection with customers who procure their supply from the distributor's territory. In response to this request, Énergir and the stakeholders proposed to deal with this topic in phase 2B, which the Régie accepted.[54] That is why this section discusses an issue that Énergir has identified and includes a proposal to change an allocation factor to address the said issue.

[53] Paragr. 177.
[54] Letter dated June 2, 2020, A-0264.

Other than the potential scenario described in the following paragraph, and considering the continued functionalization of Champion costs to the transportation service (upheld by the Régie in decision D-2020-047),[55] Énergir maintains that Northern Zone customers who procure their supply from the franchise should be allocated a share of the costs related to the Champion pipeline, as should customers in the same zone who may or may not provide their own transportation, given that the causal link is the same.[56]

According to Énergir, the only situation that would require an adjustment to be made to allocation factor FB01DN, described in paragraph 184 of the above-mentioned decision and replacing factor FB01TN on a temporary basis, would be that of Northern Zone customers who procure their supply from the franchise within the Northern Zone. For example, Northern Zone customers who procure their supply directly from a nearby renewable natural gas producer, without consuming gas that has flowed through the Champion pipelines, should not be allocated costs related to this asset.

To ensure that no costs are allocated to customers who do not use the Champion pipelines, it would be sufficient to slightly revise factor FB01DN to exclude the volumes of Northern Zone customers who procure their supply from Northern Zone producers who can be easily identified. The index of proposed allocation factors[57] has been modified accordingly. It should be noted that there are no customers in this situation at the moment. Therefore, the issue would be resolved, and Champion costs would continue to be allocated to the portion of Northern Zone customers who procure their supply from the Southern Zone, as these customers use the said pipelines to procure their supply.

In summary, Énergir proposes to allocate Champion costs according to the volumes of all customers of the distribution service in the Northern Zone, excluding the volumes of customers who procure their supply within the Northern Zone and have no need to use the Champion pipelines to transport the gas to their consumption location. Should such

[55] Paragr. 172.

[56] Response to question 1.1 of exhibit B-0498, Gaz Métro-11, Document 7, R-3867-2013, Phase 2A.

[57] Appendix 6, page 12.

volumes emerge, Énergir could exclude them on a case-by-case basis during the allocation process.

7.2.4. Load-balancing

Load-balancing is a service whose costs are made up of all of the surplus supply costs related to serving seasonal demand. Such costs must be equal to the excess peak need for a theoretical demand with an LF of 100%.

In the current functionalization method, all load-balancing costs are separated into two sub-functions: space and peak. As each cost is classified based on whether it meets space or peak need, each item is therefore allocated according to either the space factor (FB05E – Variance between average winter demand and average annual demand) or the peak factor (FB05P – Variance between peak demand and average winter demand). However, Énergir has shown that only the variation in peak demand has an influence on seasonal overage costs in relation to stable average demand.[58] That is why Énergir proposes to functionalize the costs required to meet seasonal demand on the sole basis of the customers' peak. Therefore, in the proposed allocation method, costs would instead be allocated only according to peak demand (FB05E – Variance between peak demand and average annual demand). As a result, the allocation proposed by Énergir replaces factors FB05E **(W - A)** and FB05P **(P - W)** with a new factor FB05E to be used for all costs related to seasonal load-balancing. The proposed factor is determined based on the profile of the customers. As stated in Section 2.1.3, the formula $\frac{1}{LF} - 1$ makes it possible to precisely allocate unit costs per customer. The formula can be expressed as (**P** - **A**) / **A.**[59] In order to obtain the variance between the peak volumes and the average daily consumption projected in the budget, the ratio is multiplied by the projected consumed units ([(**P** - **A**) / **A**] ***** projected units consumed). In addition, parameters **A**, **W** and **P** would no longer need to be modified for interruptible customers as they are now, because

[58] See Section 2.1.3 for more information.

[59] $\frac{1}{LF} - 1 = \frac{1}{A/P} - 1 = \frac{P}{A} - \frac{A}{A} = \frac{P-A}{A}$

interruptible costs would be handled as one of the supply tools and allocated to all customers.

However, Énergir previously identified two other types of costs to be functionalized to the load-balancing service, which do not vary according to each customer's LF: costs related to operational flexibility and supply costs not required to meet customer needs. Operational flexibility costs would be separated from seasonal load-balancing costs and then allocated according to a different factor that does not depend on the consumption profile or peak profile, namely factor FB01E – Load-balancing service volumes. Similarly, the income tax associated with the "Seasonal load-balancing" function would be allocated according to factor FB05E, while the income tax associated with the "Operational flexibility" function would be allocated according to factor FB01E. For supply costs not required to meet customer needs[60], as well as related income tax, they would be allocated based on volumes consumed (except make-up gas), with factor FB01D.

With regard to the various load-balancing cost items, the current method lists the different sites and services that are functionalized according to the ranking method, while the proposed method instead lists the various types of costs that are functionalized to load-balancing, namely seasonal load-balancing costs, operational flexibility costs and costs not required to meet customer needs.

Revenue would also be segmented between revenue related to the consumption profile (factor FB07ES) and revenue not related to the profile (factor FB07PT) in accordance with the new pricing which reflects cost causality. The current revenue factors, namely FB07EP (revenue related to peak) and FB07EE (revenue related to space), would therefore be eliminated in the new method.

To conclude, supply and transportation inventory in the rate base, as well as the revenue and costs related to the inventory of these two services, would now be found under load-balancing and would be allocated according to the seasonal consumption profile, except

[60] Note that costs not required to meet customer needs are zero in the cost allocation study made as part of this file (see exhibit Gaz Métro-5, Document 14, Appendix 6.1, row 53, column 1).

for the costs related to storage at Dawn, which would be allocated according to the volume of the load-balancing service.

CONCLUSION

Other than the cost functionalization method, a few adjustments made to the cost allocation method and the use of current data, the elements presented here were taken from Énergir's initial exhibit regarding the revision of the supply, transportation and load-balancing services. Looking ahead, Énergir invites readers to refer to exhibit Gaz Métro-5, Document 14, which continues to review Phase 2B of the case along with Part 2. The document contains Énergir's proposals with regard to pricing, interfinancing and changes to be made to the CST for the above-mentioned services with the exception of the interruptible offering.

Énergir asks the Régie to:

- **approve the method of functionalizing supply costs via the three-tier method, as described in section 5;**
- **approve the proposal to eliminate the DEA related to the fixed premiums for the Dawn storage site and for transportation tools functionalized to load-balancing;**
- **approve the method of functionalizing year-end variances related to supply costs, as described in section 6.2;**
- **approve the improved calculation method proposed for transferring seasonal costs from supply to load-balancing, as described in Appendix 5;**
- **approve the proposed cost allocation factors, as described in Appendix 6 of this document;**
- **take note of the responses to the follow-ups relating to decision D-2016-126 contained in sections 2.2.6, 7.1 and Appendix 7 and declare them satisfactory;**
- **take note of the responses to the follow-up related to decision D-2020-047 contained in section 7.2.3 and declare them satisfactory.**

APPENDIX 1
ALLOCATION OF SEASONAL COSTS RELATED TO SUPPLY

As presented in section 2.2.4, the seasonal costs related to supply should be allocated based on the real impact of the variation in consumption and the supply price during the year for each customer.

Although this distribution is theoretically optimal, the allocation of load balancing costs related to poses a problem. The real impact of the variation in consumption is hard to measure per customer or group of customers in Énergir's specific context. Since Énergir uses storage both to reduce its supply delivery costs (sites in franchise) and to reduce its seasonal purchasing costs, the cost related to supply includes a fixed portion. Furthermore, transfers between supply and load balancing are one way, i.e. transfers cannot be made only to reduce supply costs, even if the winter prices are lower than the summer prices.[1]

For example, if all purchases were made based on need, then the seasonal cost of a winter purchase in comparison with a purchase in summer would be reflected directly in Énergir's cost. If the price is $3 in summer and $4 in winter, any seasonal purchases in winter above the annual average would generate an additional cost of $1. However, if the price is $3 in summer and winter, Énergir incurs no seasonality cost. In this case, the real impact on the customers would be $0, regardless of their consumption profile. Since the transfers between the supply and load balancing costs are one way, the impact on the customers would also be $0 if the winter prices were lower than the summer prices.

But since Énergir uses storage tools, the real impact on its costs is different from a structure where all purchases are made on the spot market. As a result, when the price is $3 in summer and $4 in winter, the impact is mitigated by the quantities in storage. For every unit stored, the seasonal cost is not $1 but rather the cost of having the storage tool, if it was purchased specifically to reduce seasonal costs. When the storage tool is also required for other reasons, the cost of having the tool to reduce seasonal costs is mitigated.

[1] See decision D-2015-177, paragraphs 90 and 92.

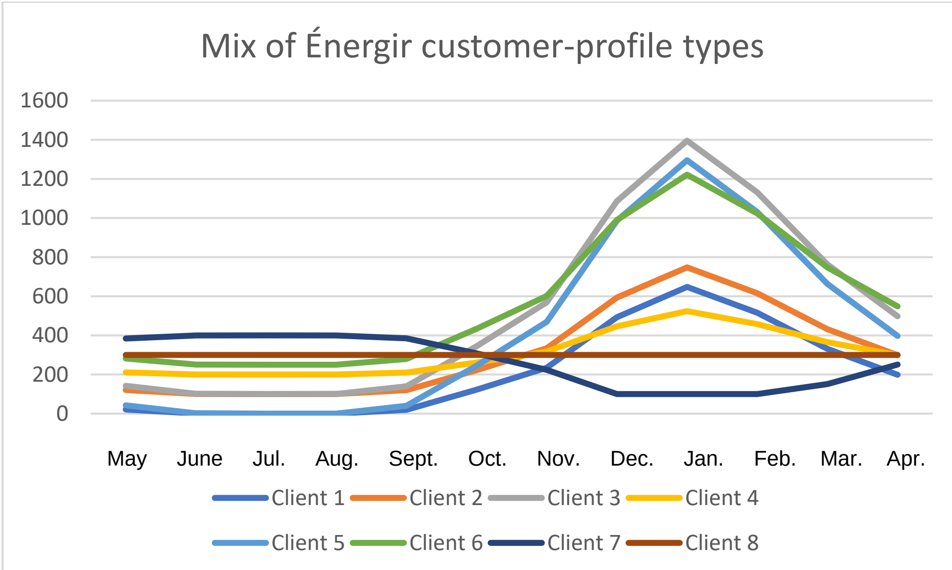
It is therefore hard to calculate the real impact per customer or group of customers on an annual basis, taking into account the impact of the storage tools on the seasonality costs. For the allocation of seasonal costs related to the commodity, no method accurately reflects the impact for Énergir in a given year.

Although the cost causation showed that in the short term (for one year), no specific factor allowed for correctly allocating the costs between customers with different consumption profiles, the reality of Énergir customers is that in general, they have relatively homogeneous consumption profiles, as demonstrated in the paragraphs below. Among the homogeneous profiles, the use of an explanatory profile progression factor allows for a reasonable break down of the costs caused by the entire profile, even if this factor is not specifically related to the cost to be allocated (see section 2.2.2).

Homogeneous consumption profiles are comprised of a basic portion (stable) and a portion affected by the temperature. The seasonality of the supply costs comes from the combination of the higher prices in the winter season and the variation in volume of customers affected by temperature. Degree-days are therefore a decisive explanatory function in Énergir’s seasonality costs. Since temperature is behind the higher prices in winter and also the increase in the customers’ consumption, an allocation factor based on the LF should allow for a fair distribution of costs as well as sending a good price signal.

If we only consider standard customer profiles, i.e. customers with a relatively stable base and variable consumption based on temperature, the use of the peak factor allows for a representative cost breakdown. To illustrate this, Graph 1.1 presents eight typical consumption profiles of customers.

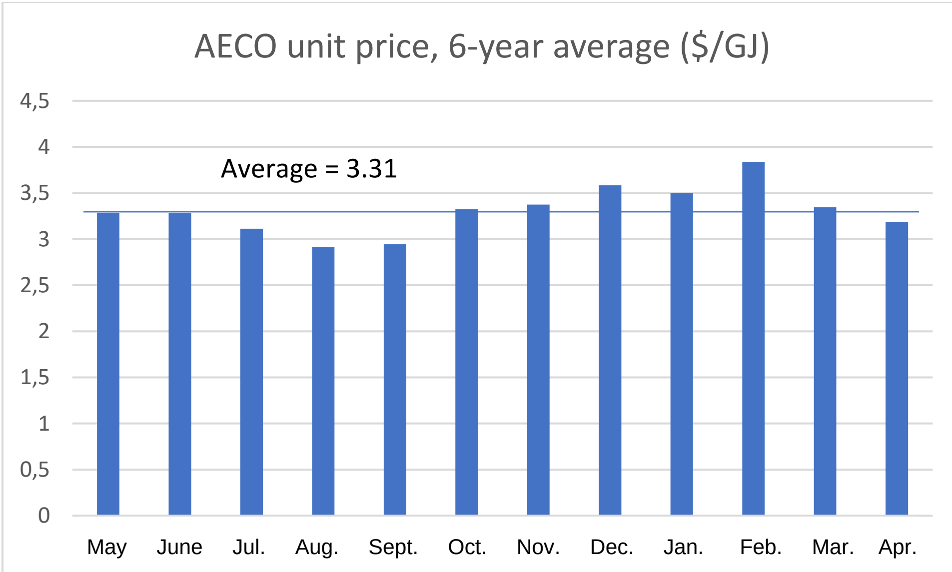
Graph 1.1



The mix of customers presented in Graph 1.1 includes customers with a roughly higher base consumption as well as a consumption that is more or less related to temperature. There is also one stable customer and one customer that consumes mainly in summer.

To determine the long-term effect of these profiles, Graph 1.2 presents the average price per period at AECO over six years, which represents all data available since natural gas prices fell in 2008, after the beginning of shale gas operations. Data prior to the price decrease were not used, in order to provide a price history that is more representative of the current context.

Graph 1.2



The data show seasonality between the October-March and April-September periods. The prices are significantly higher from December to February, and significantly lower from July to September.

By cross-referencing these profiles with the prices, we can establish the average cost of supply per customer (based on spot purchases), the total cost per customer and the allocation results:

Table 1.1

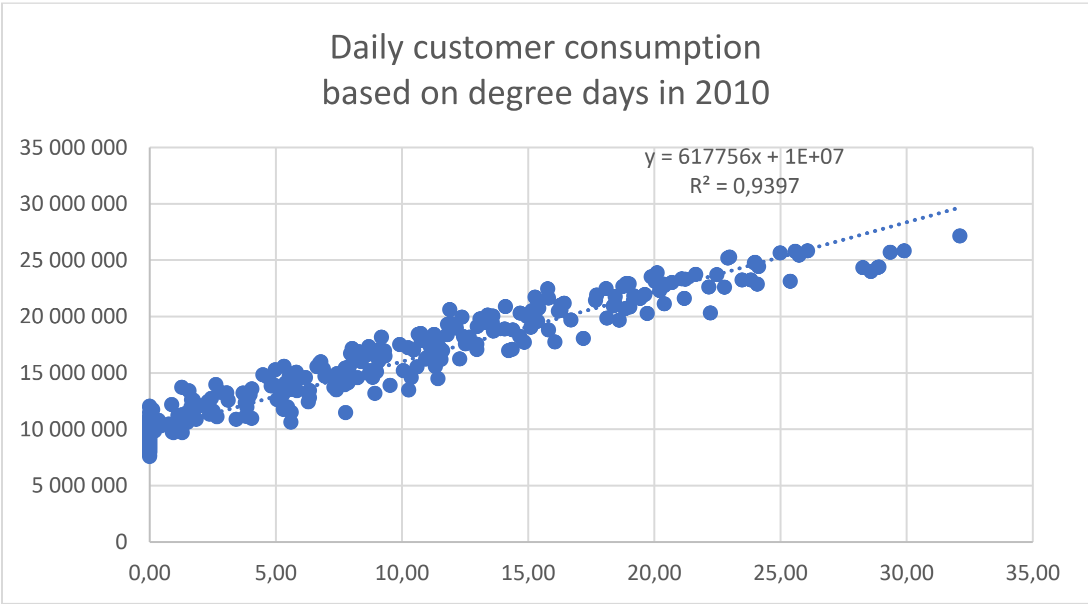
	CU (%)	Average Cost ($/GJ)	Volume (m³)	Total cost ($)	Allocation based on CU ($)	Differential ($)
	(1)	(2)	(3)	(4)	(5)	(6)
Customer 1	33	3,51	2 585	532	520	12
Customer 5	33	3,51	5 170	1 065	1 040	24
Customer 3	38	3,48	6 370	1 065	1 040	24
Customer 2	42	3,45	3 785	532	520	12
Customer 6	47	3,42	6 878	799	780	18
Customer 4	59	3,38	3 693	266	260	6
Customer 8	100	3,31	3 600	0	0	0
Customer 7	267	3,22	3 203	-298	-201	-97

For all customers with a relatively stable base profile and increased consumption during cold weather, the allocation based on LF generates a result very close to the cost based on real supply purchases. Furthermore, for all these profiles, the average per-unit cost of supply declines as the LF increases. Over several years, the LF is therefore very representative of the supply costs generated for stable or heating profiles. The use of the LF to allocate these costs allows for adequate cost allocation, even for years when there is no price seasonality. The costs related to seasonal supply are therefore always properly allocated.

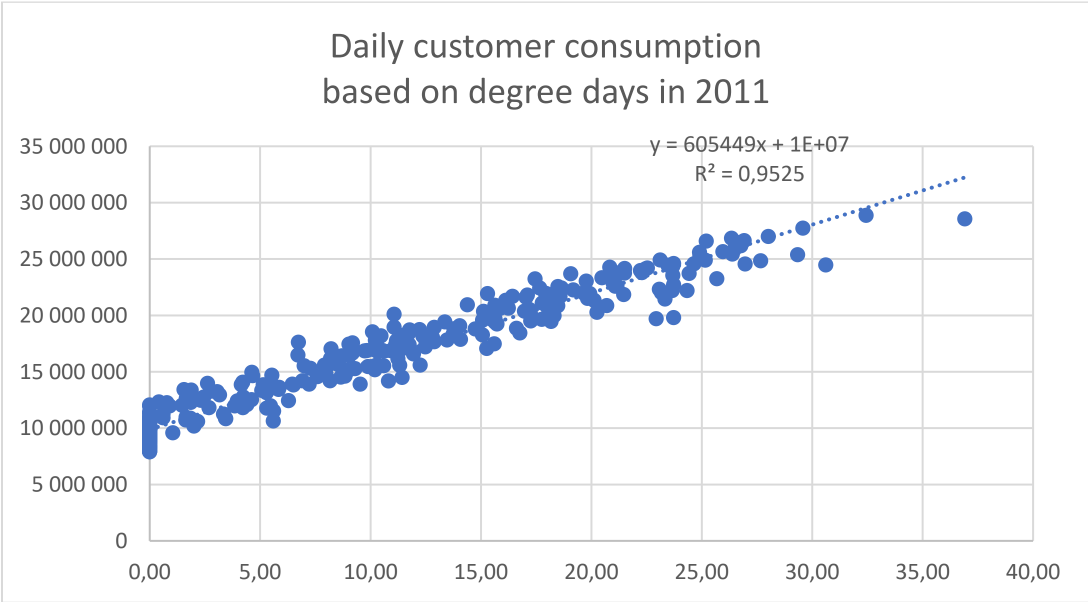
An examination of the real consumption of Énergir's customers between 2010 and 2014 also demonstrates that the entire customer body consumes based on this type of profile, i.e. according to a basic consumption and temperature-based consumption.

The following tables represent the relationship between customer consumption and degree-days (base 13), with no distinction for customer rate, weekday or weekend, or temperature the day before. The correlation between the daily consumption variance and the degree-day variance is very strong, with an R^2 from 0.93 to 0.97 for every year from 2010 to 2020. Therefore, the assumption stating that customers, in general, have a profile defined by relatively stable basic consumption and variable consumption based on temperature is reasonable.

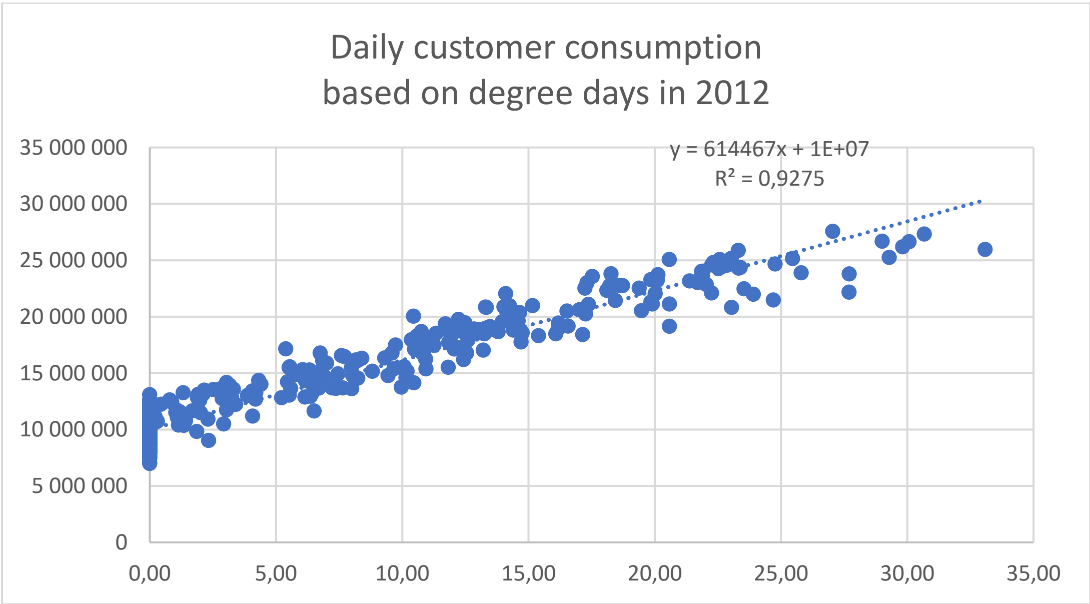
Graph 1.3



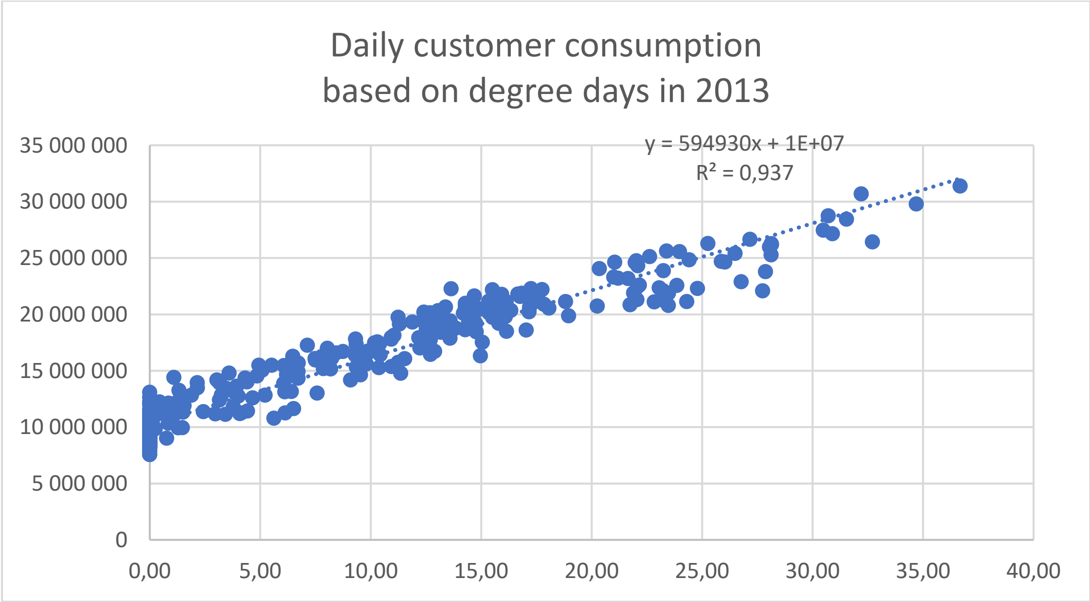
Graph 1.4



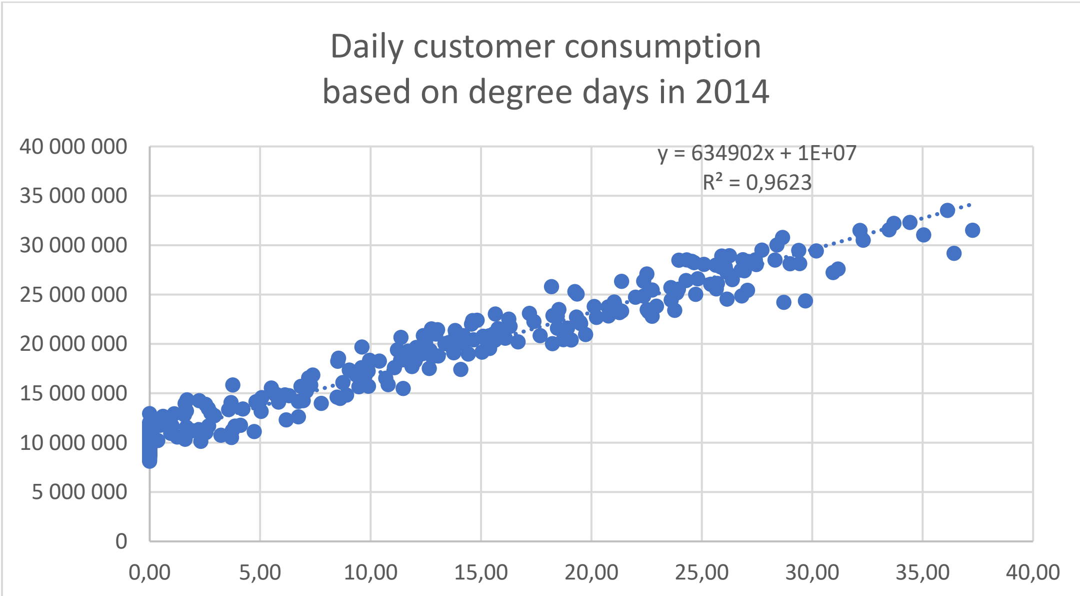
Graph 1.5



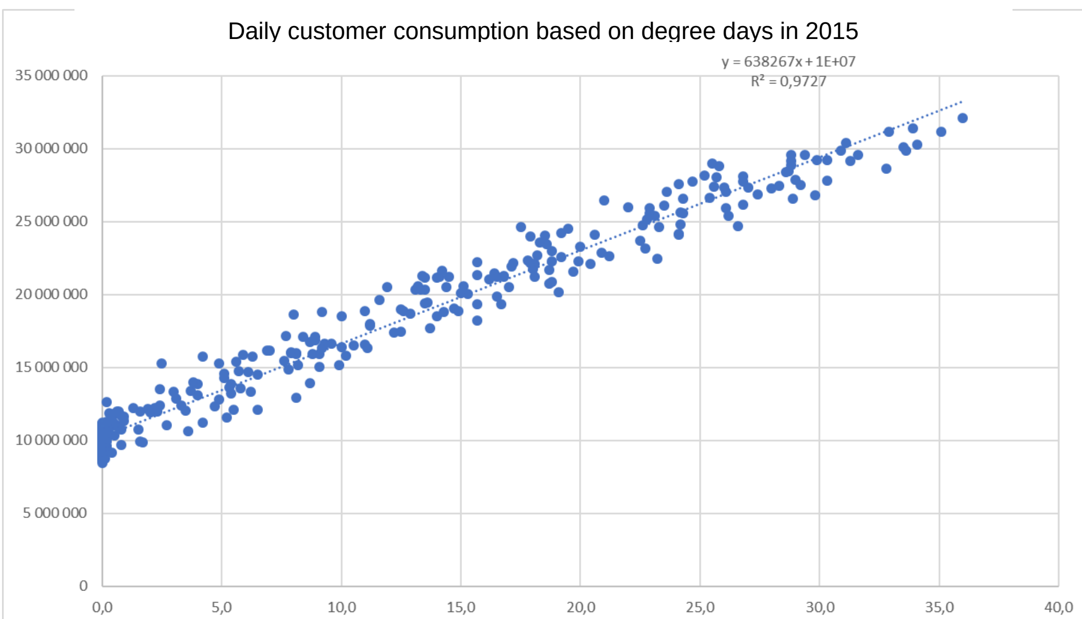
Graph 1.6



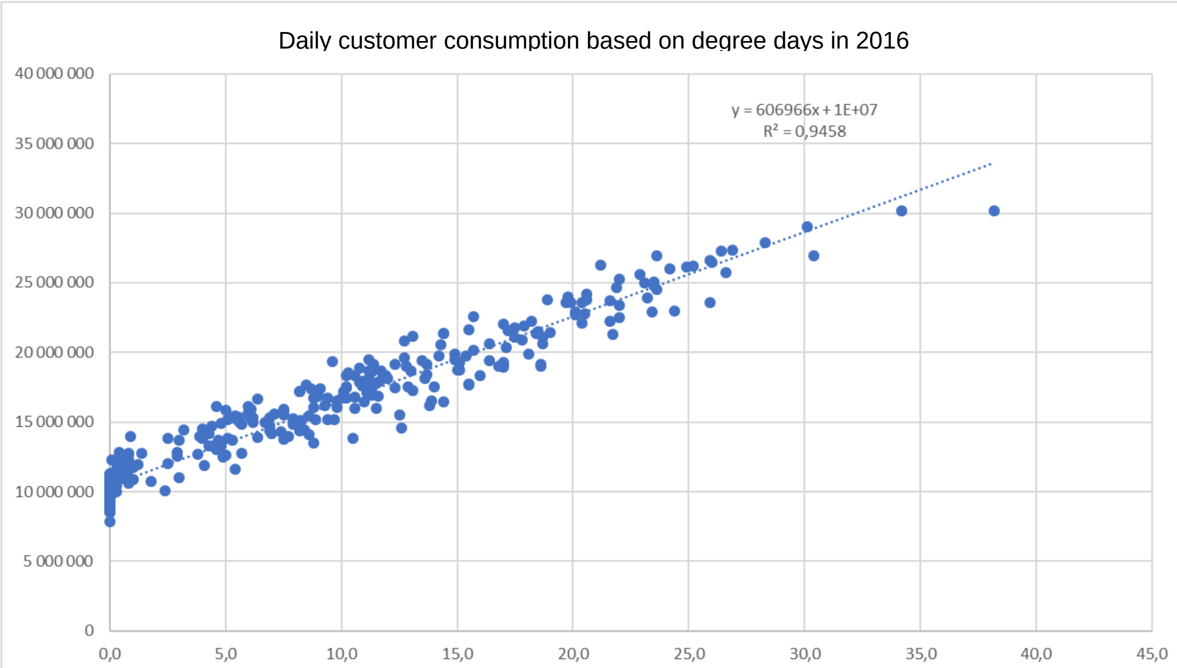
Graph 1.7



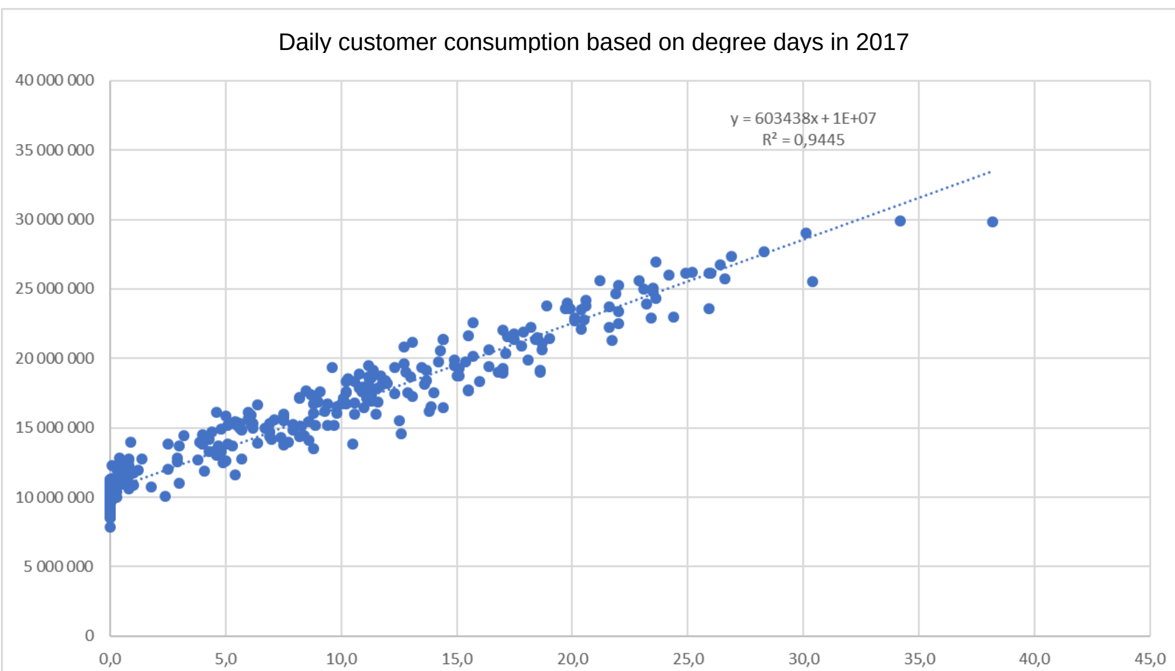
Graph 1.8



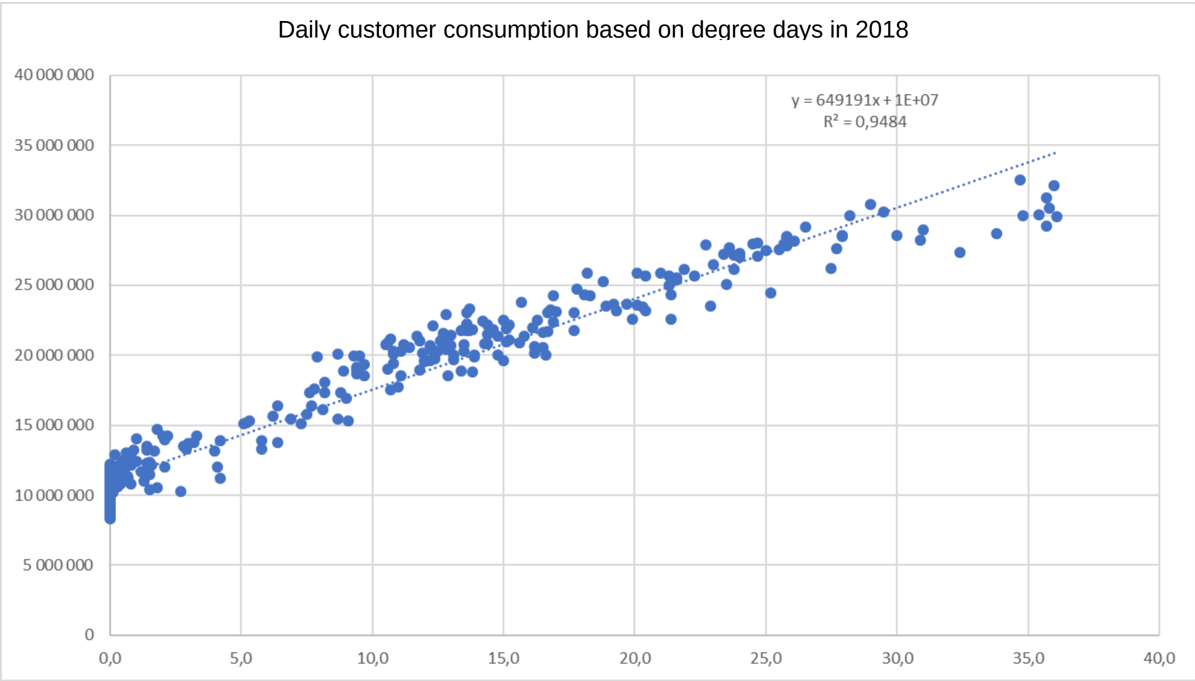
Graph 1.9



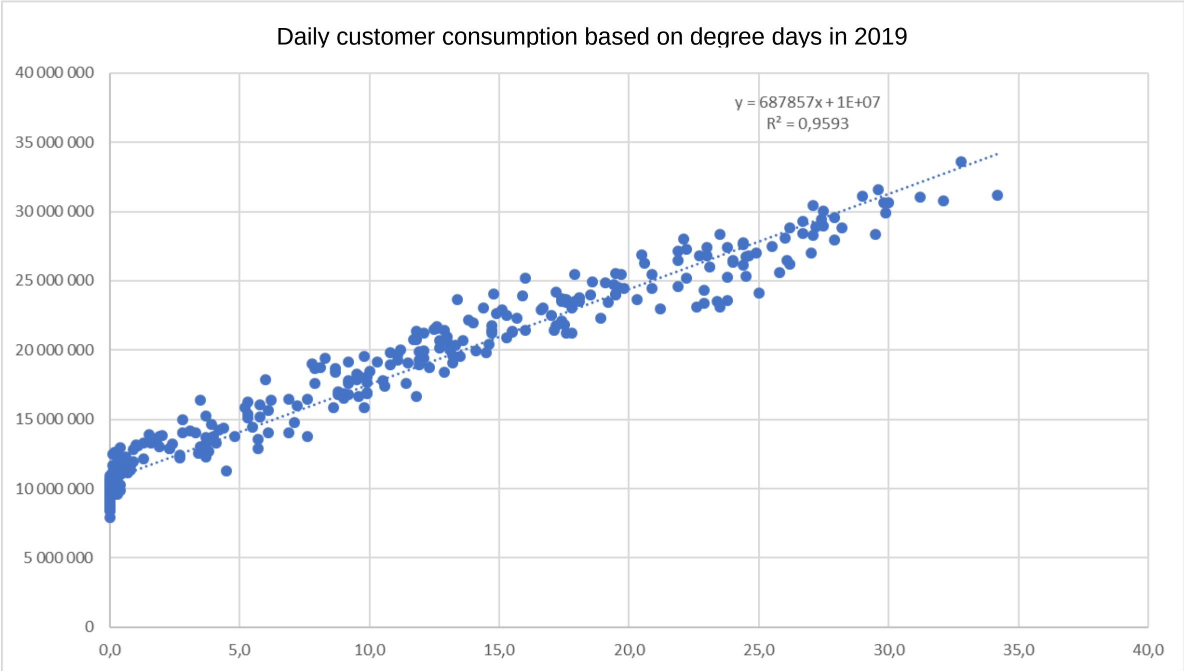
Graph 1.10



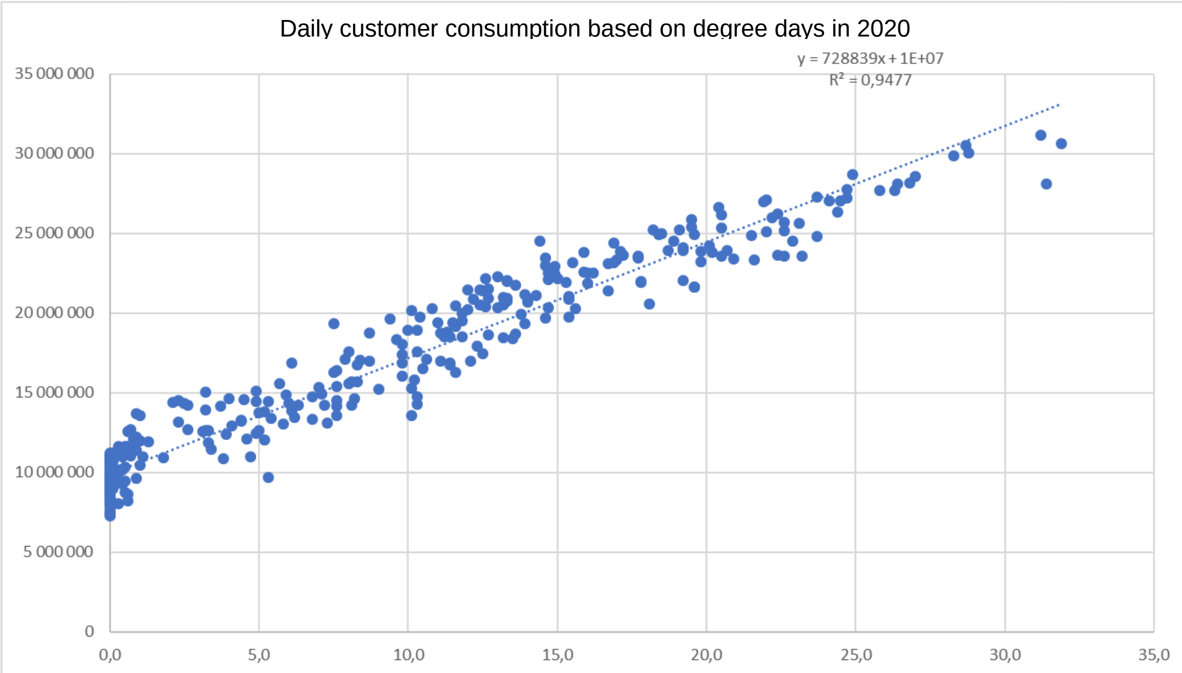
Graph 1.11



Graph 1.12



Graph 1.13


Daily customer consumption based on degree days in 2020
y = 728839x + 1E+07
R^2 = 0,9477
35 000 000
30 000 000
25 000 000
20 000 000
15 000 000
10 000 000
5 000 000
0
0,0
5,0
10,0
15,0
20,0
25,0
30,0
35,0

APPENDIX 2: AVERAGE AND EXCESS DEMAND METHOD

To fully understand the average and excess demand proposal, Énergir will review herein the general lines of the reasoning behind this method of allocating the costs between the transportation and storage services.

The *Approvisionnements Montréal, Santé et Services sociaux* (AMSSS) evidence, produced in case R-3323-95 on cost allocation, explains that the transportation costs must be functionalized based on average demand (100% LF) otherwise, the rate would not be fair. Any excess over average demand is therefore considered to be a load balancing cost. The following example was given:

- For a distributor with two consumption periods in the year, there is only one customer with uniform consumption of 50 units in each period, for a total of 100 units. At a transportation price of $100 per unit, the total cost to deliver the natural gas to this customer is $5,000.
- This same distributor gets a second customer that consumes 0 units in the first period and 100 units in the second period. The distributor must now provide 50 units in the first period and 150 units in the second period. The price of storage from one period to the other is $60 per unit in franchise.
- The distributor's options for delivering the natural gas would therefore be as follows:
  - Purchase 150 transportation units throughout the year for $15,000.
  - Purchase 100 transportation units throughout the year for $10,000 and store 50 units in the first period for $3,000, for a total of $13,000.

In this example, using average demand (equal to 100% LF), 100 units are allocated to transportation costs, for a total of $10,000. Since each customer consumes the same annual quantity, this invoice will be divided in two, i.e. $5,000 for the first customer and $5,000 for the second. The excess over these costs, $3,000, is allocated to load balancing. Based on the rules for allocating load balancing among customers, as the first customer has uniform consumption, none of these costs will be allocated to this customer and, as a result, the second customer will receive a $3,000 load balancing invoice. Any other allocation would not be fair for one of the customers.

In its evidence, the AMSSS also noted that the total transportation capacity contracted from TransCanada Pipelines Limites (TCPL) was higher than the customers' average demand. As such, the cost for the transportation contracted in excess of the average demand is a load balancing cost.

To illustrate this situation, let us go back to the previous example, with one change:

- The supply cannot be stored from one period to another in franchise. As a result, the additional cost of transportation to a non-franchise storage for one period to the other is $50, for a total storage cost of $110 for from one period to the other.
- The distributor's options for delivering the natural gas would therefore be as follows:
  - Purchase 150 transportation units throughout the year for $15,000.
  - Purchase 100 units of transportation throughout the year for $10,000 and store 50 units for the first period for $5,500, for a total of $15,500.

In this modified example, the distributor is in a better position if it buys 150 transportation units throughout the year. Despite a LF of just 66.6%, the distributor will save $500 in comparison to the storage option. In this case, the distributor substitutes storage with additional transportation. Luckily for the first customer, based on average demand, only the equivalent of 100% LF will be charged to transportation, i.e. 100 units for a total of $10,000. This first customer will continue to receive an invoice of $5,000. The excess over the equivalent of 100% LF will be allocated to load balancing, i.e. $5,000, and the second customer will receive an invoice of $10,000 for its use, which is fair. Once again, not only would any other allocation been unfair to the customer, but it would also have made a bigger difference between the transportation rate and the market price.

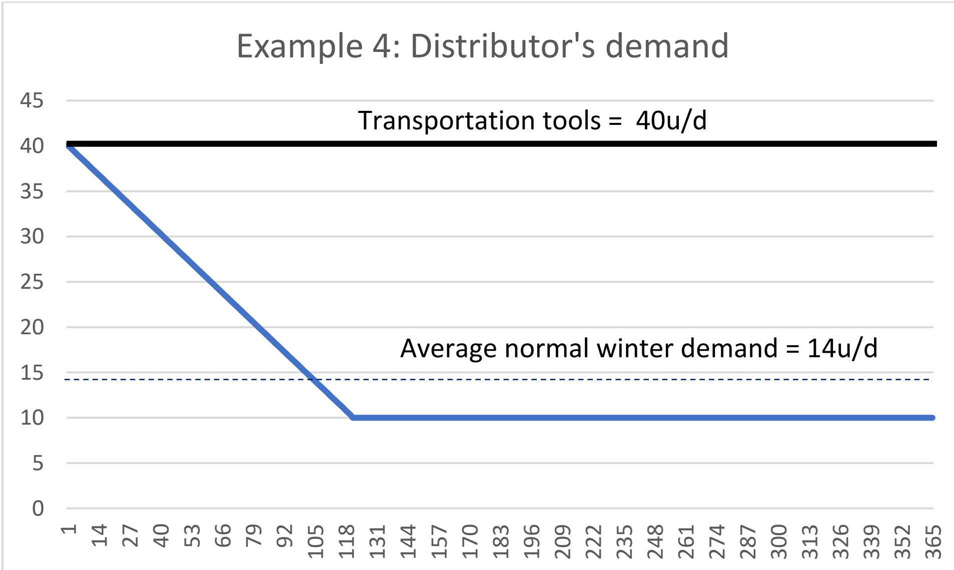
APPENDIX 3: ANALYSIS OF THE IMPACT OF THE RANKING METHOD ON THE FUNCTIONALIZATION OF COSTS BETWEEN TRANSPORTATION AND LOAD BALANCING

Énergir analyzed the impact of the ranking method on the functionalization of costs between transportation and load balancing. First, before beginning the analysis, Énergir would like to offer a few clarifications:

- In terms of gas supply, the order in which the tools are used cannot necessarily be changed.
- For the purposes of the analysis, Énergir assumes that the tools used in the example are completely interchangeable without restriction. This does not reflect the reality of the tools held by the distributor, but it allows us to determine the impact of using ranking to allocate the costs between stable and seasonal profiles.
- In the current functionalization method, the ranking is based on all available tools, regardless of whether they are annual or seasonal.
- Ranking meets real demand, which contains a stable portion and a seasonable portion.
- The examples were constructed to clearly demonstrate the impact of using the ranking method on the functionalization of costs between transportation and load balancing. Based on the Énergir supply plans, however, this impact is weaker than the results obtained in these examples.

To illustrate the impact of using ranking to functionalize the costs between the stable profile (transportation) and the seasonal profile (load balancing), example 4 (distributor's demand – section 2.1) presented in the analysis of the supply cost causation is reused.

Graph 3.1



To simplify the explanations, the distributor simply purchases the transportation tools to meet maximum need. To supply the customer, the distributor therefore has to purchase transportation tools for a total of 40 units per day. Let us assume that the distributor has the following transportation tools to supply the customers:

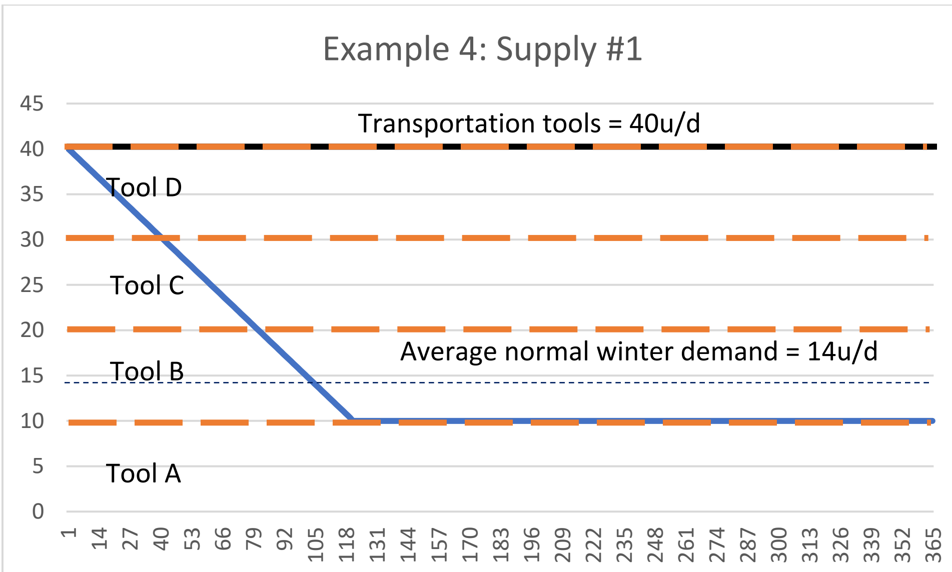
Table 3.1

Tool	Daily capacity *(units)*	Fixed cost per unit *($/u)*	Total cost per day *($)*
A	10	1.00	10
B	10	1.50	15
C	10	2.00	20
D	10	2.50	25
Total	**40**	**1.75**	**70**

Based on this assumption, as the cost is set by the unit, the total cost will be the same, i.e. $70 per day. Since in this example all tools are completely interchangeable, the customers can be supplied based on 24 separate scenarios (for example, A-B-C-D, B-A-C-D, C-A-B-D, etc.).

Among the 24 different possible supply scenarios, here are two separate cost scenarios that demonstrate the impact of the ranking method on the allocation of costs between the stable and seasonal profiles:

Graph 3.2



If the distributor used these tools successively, then the costs allocated to transportation and load balancing would be as follows:

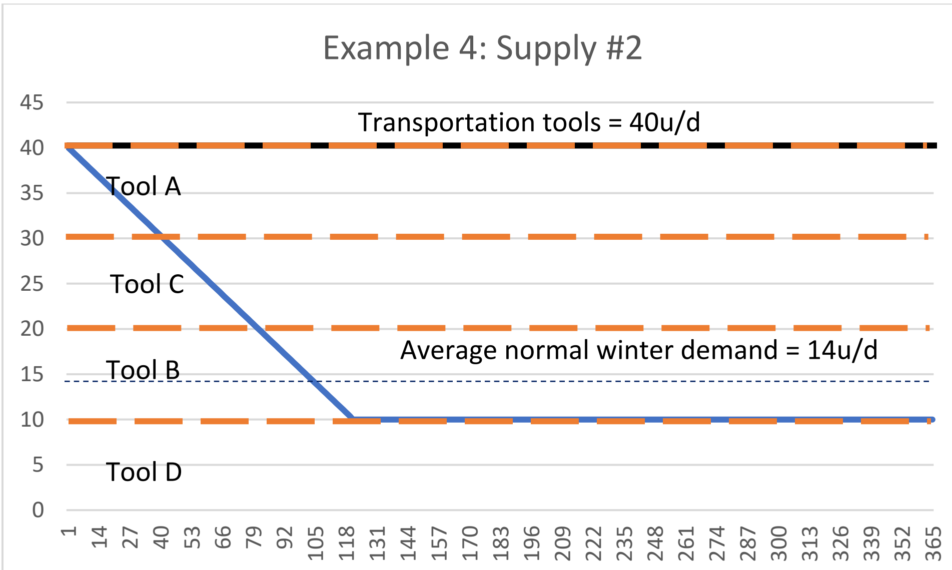
Table 3.2

Tool	Daily capacity (units)	Fixed cost per unit ($/u)	Total cost per day ($)	Transportation units (units)	Balancing units (units)	Transportation cost ($)	Balancing cost ($)	Total cost ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
A	10	1.00	10	10	0	10	0	10
B	10	1.50	15	4	6	6	9	15
C	10	2.00	20	0	10	0	20	20
D	10	2.50	25	0	10	0	25	25
Total	**40**	**1.75**	**70**	**14**	**26**	**16**	**54**	**70**

The total transportation cost based on this ranking is $16 per day, which corresponds to a rate of $1.14 per unit.

Compare this cost to a second supply scenario:

Graph 3.3



If the distributor used these tools successively, then the costs allocated to transportation and load balancing would be as follows:

Table 3.3

Tool	Daily capacity *(units)*	Fixed cost per unit *($/u)*	Total cost per day *($)*	Transportation units *(units)*	Balancing units *(units)*	Transportation cost *($)*	Balancing cost *($)*	Total cost *($)*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
A	10	1.00	10	0	10	0	10	10
B	10	1.50	15	4	6	6	9	15
C	10	2.00	20	0	10	0	20	20
D	10	2.50	25	10	0	25	0	25
Total	**40**	**1.75**	**70**	**14**	**26**	**31**	**39**	**70**

The total transportation cost based on this ranking is $31 per day, which corresponds to a rate of $2.21 per unit.

In both scenarios, the total cost is still $70 per day, but the functionalization of the costs based on the ranking method determines which costs are allocated to the stable or seasonal profile. In the first scenario, the proportion allocated to the stable consumption profile is 23% (16/70) of the total costs, while in the second scenario, the proportion increases to 44% (31/70).

Furthermore, in the case where the distributor only has to meet the stable portion of the demand, the tools held by the distributor would not total 40 units per day, but only 14. There are therefore tools among all the tools held that are only required because the distributor must also meet seasonal demand. However, in both scenarios, the tools are chosen to meet the total need, not to meet the specific needs of either profile type.

Therefore, the use of the ranking method to functionalize the costs between the stable and seasonal profiles may have an impact on the costs allocated to each type of profile. The reduction in total supply costs could, for example, based on this method, increase the portion of costs functionalized based on a stable profile (therefore, to the transportation service). Likewise, no matter which ranking is used, it would always impact, in one way or another, the costs functionalized based on the stable and seasonal portions. And yet the functionalization of costs based on stable and seasonal profiles should not be influenced by the short- or long-term optimization of supplying total demand.

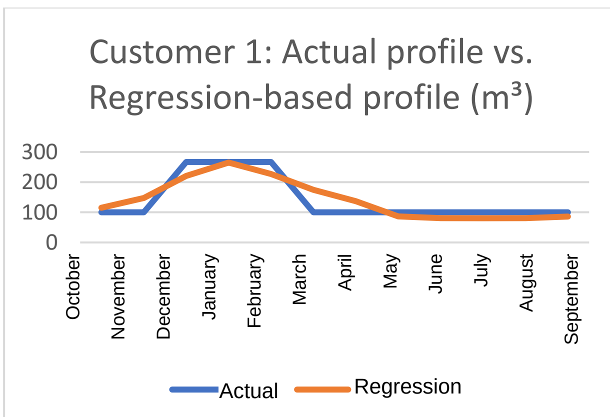
APPENDIX 4:
IMPACT OF CUSTOMERS IN A PEAK MODEL USING REGRESSION

Peak-day demand is an essential element in developing the gas supply plan. It is evaluated based on a regression whose main explanatory variable is temperature (expressed in degree-days).

Using this basic principle, a theoretical explanation can be developed to demonstrate that the causality of the supply costs is related to the projected variation in a customer's consumption relative to the temperature.

According to a model using a simple regression based on the degree-days of the day, any customer who consumes more when the temperature is colder will have an upward effect on the overall peak demand estimated by the distributor. The following graphs present different theoretical examples of customers whose "actual" [1] profile is compared to the profile obtained using a regression based on the actual degree-days.

Graph 4.1

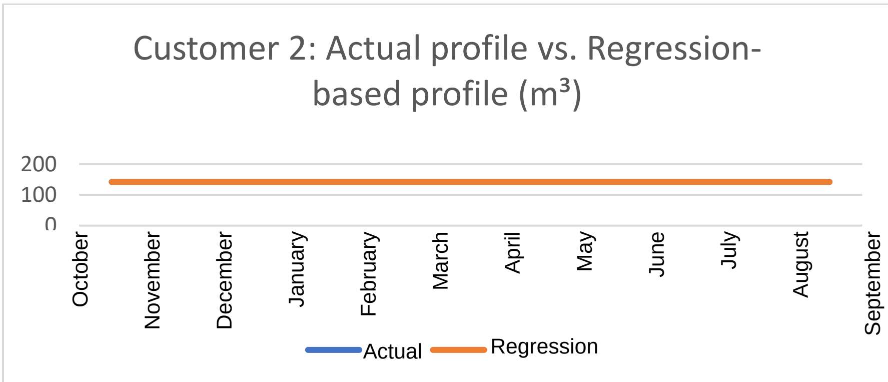


For customers who consume more from December to February, but in a stable manner, a regression will nevertheless result in a heating-type profile, with a higher demand during the peak day than in the other months. At peak, the customers will take a volume equivalent to their actual consumption. Off peak, the regression will result in a lower volume than the actual

[1] The term "actual" is used to indicate that the profile concerned has not been obtained with a regression. It is nevertheless a theoretical profile example.

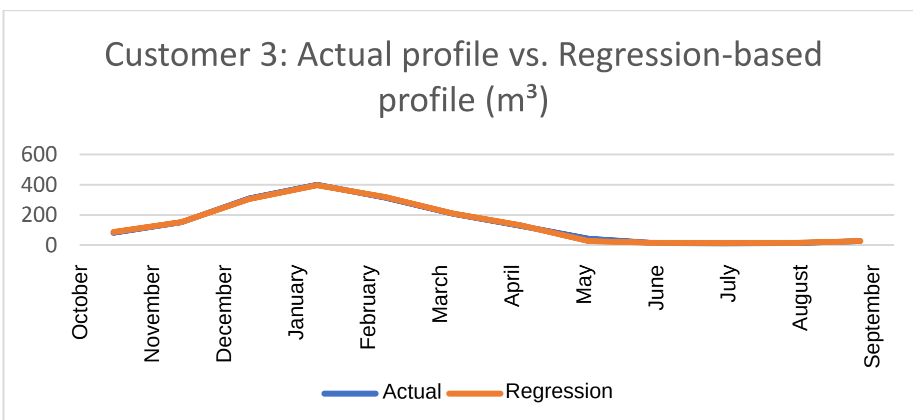
consumption. If Énergir had customers with this profile, their impact on the costs would be closer to the regression than the actual.

Graph 4.2



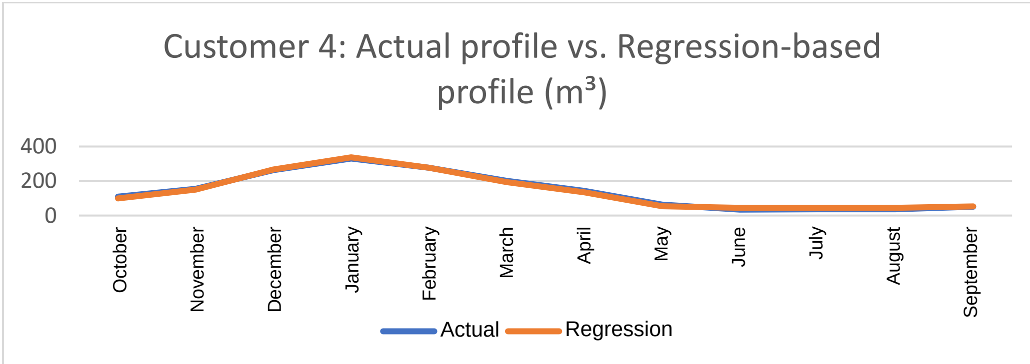
For customers whose consumption is stable, the regression mirrors the actual consumption. However, Énergir notes that no customer's consumption is perfectly stable. All consumption profiles are affected in some way by temperature.

Graph 4.3



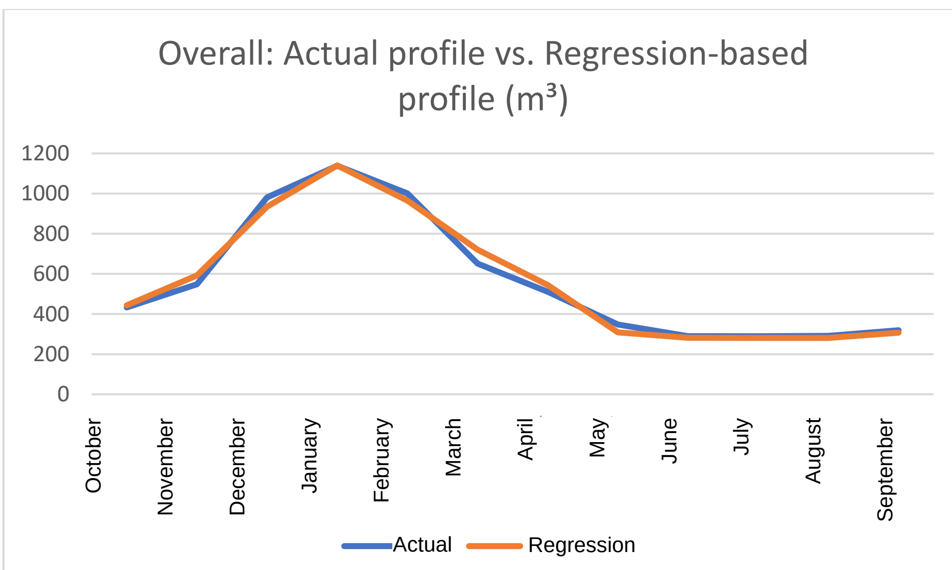
The graph 4.3 represents the profile of the small rate D_1 customers. The basic consumption in summer is lower and increases in winter. The consumptions estimated by the regression model are very close to the actual figures.

Graph 4.4



The graph 4.4 represents the profile of the large rate D_1 customers. It is similar to the profile of the small customers presented in Graph 4.3, except that the basic consumption in summer is higher. Once again, the consumptions estimated by the regression model are very close to the actual figures.

Graph 4.5



The result obtained by combining the consumptions is equal to the sum of the regressions by customer. In cumulating the profiles, the overall customer demand obtained with the regression is close to the actual demand. However, when each customer's individual peak (instead of the peak calculated by group or overall) is considered, the sum of the customer peaks always exceeds the regression result. The combined individual peaks do not all coincide whereas a peak calculated by regression is always coincident.

Based on the overall customer profile observed between 2010 and 2014[2], the variation in demand closely tracks the variation in degree-days. So customers are all influenced to some extent by the temperature. The relationship can be direct, null or inverse and in all cases is well represented by the regression model. Since the relationship between overall demand and temperature is very strong, this also indicates that customers with a more erratic consumption profile relative to the temperature (e.g. Customer 1 in Graph 4.1) have an almost non-existent impact on total demand. Therefore, the regression model used enables the most accurate estimate of customer consumption.

The causality of the costs is thus connected only to the projected variation in a customer's consumption relative to the temperature. This relationship is represented by the difference between the peak factor (P) and the average demand (A). This remains true regardless of the customer's actual profile during the winter, as demonstrated in the cases illustrated.

[2] Gaz Métro-5, Document 12, Appendix 1, pp. 6 to 8.

APPENDIX 5

FUNCTIONALIZATION FOR SEASONAL SUPPLY PURCHASE COSTS

In decision D-2015-177, the Régie approved the functionalization method for costs related to supply purchases when the purchases are made elsewhere than at the reference location. This functionalization method used at Dawn also included the calculation method for the seasonal costs included in supply.

In order to simplify this method of processing the seasonal costs included in supply purchases, Énergir analyzed the possibility of calculating the portion of costs to be transferred to load-balancing based on the annual average per-unit cost rather than on the total costs evaluated from the uniform distribution of purchase volumes.

A. FUNCTIONALIZATION OF SUPPLY PURCHASES FROM ANNUAL AVERAGE PER-UNIT COSTS

Based on the principle of uniform delivery, the supply price should be free from seasonal effect. This price should therefore be equal to the price that a customer with a completely stable profile would pay to purchase supply from the reference point.

In the current method, the total supply purchase volume is distributed uniformly over each day of the year, which makes it possible to find the total cost based on a uniform purchase profile. This can be observed in the 2019 annual report,[1] on page 5 of exhibit B-0043, Énergir-9, Document 2. Table 5.1 provides an excerpt of the exhibit.

[1] R-4114-2019

Table 5.1

Transfer from S to L in the 2019 annual report – Current method

N° de ligne		oct-18	nov-18	déc-18	janv-19	févr-19	mars-19	avr-19	mai-19	juin-19	juil-19	août-19	sept-19	TOTAL
		31	30	31	31	28	31	30	31	30	31	31	30	365
	TRANSFERTS DE COÛTS POUR LA SAISONNALITÉ													
	1) Transfert du F au É pour saisonnalité des achats totaux													
	Achats totaux													
23	Volume d'achats totaux (GJ) (=l.1 + l.8 + l.14)	6 728 850	13 622 932	13 044 420	15 895 665	14 322 567	13 099 598	8 197 034	4 350 776	2 664 207	2 629 242	2 627 088	4 755 744	101 938 123
24	Coûts d'achats fonctionnalisés au F ($) (=l. 5 + l. 11 + l. 19)	27 942 968	71 150 529	69 630 171	68 118 986	51 635 994	49 695 675	26 398 604	13 158 888	7 280 016	7 028 226	6 757 133	13 041 552	411 838 742
25	Coût moyen des achats au F ($/GJ) (=l.24 / l.23)	4,153	5,223	5,338	4,285	3,605	3,794	3,221	3,024	2,733	2,673	2,572	2,742	4,040
26	Volumes selon profil d'achats mensuels (GJ)	6 728 850	13 622 932	13 044 420	15 895 665	14 322 567	13 099 598	8 197 034	4 350 776	2 664 207	2 629 242	2 627 088	4 755 744	101 938 123
27	Volumes selon profil d'achats uniformes (GJ)	8 657 758	8 378 476	8 657 758	8 657 758	7 819 911	8 657 758	8 378 476	8 657 758	8 378 476	8 657 758	8 657 758	8 378 476	101 938 123
28	Coûts selon profil d'achats mensuels ($)	27 942 968	71 150 529	69 630 171	68 118 986	51 635 994	49 695 675	26 398 604	13 158 888	7 280 016	7 028 226	6 757 133	13 041 552	411 838 742
29	Coûts selon profil d'achats uniformes ($)	35 953 165	43 759 522	46 214 487	37 101 797	28 192 493	32 844 759	26 982 938	26 185 323	22 894 406	23 143 054	22 268 620	22 976 075	368 516 640
30	**Portion Équilibrage ($)** (= l.28 - l.29)													**43 322 102**
31	**Portion Fourniture ($)** (= - l.30)												Total	**-43 322 102**

Thus, the total cost based on a uniform purchase profile is $368.5M (line 29). By dividing this cost by the total purchase volumes (101,938,123 GJ – line 23), a price of $3.615/GJ is obtained. This price corresponds to the uniform price that the customers have to pay in supply.

The same price could be obtained using only monthly payments, without the uniform distribution of the volumes, as illustrated in the below table:

Table 5.2

Calculating the uniform average per-unit cost – Proposed method

N° de ligne		oct-18	nov-18	déc-18	janv-19	févr-19	mars-19	avr-19	mai-19	juin-19	juil-19	août-19	sept-19	TOTAL
		31	30	31	31	28	31	30	31	30	31	31	30	365
23	Volume d'achats totaux (GJ) (=l.1 + l.8 + l.14)	6 728 850	13 622 932	13 044 420	15 895 665	14 322 567	13 099 598	8 197 034	4 350 776	2 664 207	2 629 242	2 627 088	4 755 744	101 938 123
24	Coûts d'achats fonctionnalisés au F ($) (=l. 5 + l. 11 + l. 19)	27 942 968	71 150 529	69 630 171	68 118 986	51 635 994	49 695 675	26 398 604	13 158 888	7 280 016	7 028 226	6 757 133	13 041 552	411 838 742
25	Coût moyen des achats au F ($/GJ) (=l.24 / l.23)	4,153	5,223	5,338	4,285	3,605	3,794	3,221	3,024	2,733	2,673	2,572	2,742	4,040
	Prix uniforme ($/GJ) (= ∑ (l.25*Nb jours du mois/365))	0,353	0,429	0,453	0,364	0,277	0,322	0,265	0,257	0,225	0,227	0,218	0,225	**3,615**

Therefore, the seasonal cost that should be transferred to load-balancing ($43.3M) is exactly the same as the amount obtained using the old method, after applying the following equations, which use per-unit costs to help simplify the calculation of the supply cost and the transfer of supply costs to load-balancing (S to L):

1) Supply cost = Total purchase volumes * Uniform per-unit purchase cost
= 101,938,123 GJ * $3.615/GJ = $368.5M

2) Transfer from S to L = Total purchase volumes * (Current per-unit purchase cost – Uniform per-unit purchase cost)
= 101,938,123 GJ * ($4.040/GJ – $3.615/GJ) = $43.3M

The purchase functionalization method can therefore be calculated from the annual per-unit costs, without using a uniform monthly distribution of purchase volumes or changing the results.

B. PROPOSED CHANGE TO THE TRANSFER OF SEASONAL COSTS INCLUDED IN THE SUPPLY COST

In the current method described in the previous section, the seasonal cost of the commodity is calculated based on system gas purchase volumes from that year. However, these purchases do not represent all of the costs charged to the supply service.

In fact, the supply cost can also be impacted by purchases at the price of the distributor's supply service (direct purchases with transfer of ownership) and by rebilling at a supply cost different from the cost approved for the period. For this reason, Énergir proposes integrating these elements into the new method in order to take all supply costs into account rather than relying solely on the supply purchase cost, as the current method does. This proposal should make it possible to calculate seasonal costs more precisely. The calculation would be made as follows:

Costs of supply sold as system gas (cost of merchandise sold, including direct purchase with transfer of ownership)

\+ Net costs entered in the price differential account throughout the year

<u>+ Costs of variations in system gas inventory throughout the year</u>

Actual cost of acquiring supply

By comparing the cost of acquiring supply with the uniform purchase cost, the full overage cost related to seasonal purchases can be determined.

The following table provides an example of how the seasonal cost included in the purchase cost at the reference location could be calculated using data from the 2019 annual report.

Table 5.3

Line	Description	Volumes *(10^3 m^3)*	Cost *($000)*	Reference
(1)	System gas and direct purchase with transfer of ownership	3,029,166	444,666	R-4114-2019, Énergir-9, Document 1, p. 2, l. 2, c. 2 and l. 2, c. 5
(2)	Variation in price differential		20,412	Previously unpublished, 2019 info on cost of gas
(3)	Cost of variations in inventory	103,431	9,816	Previously unpublished, 2019 info on cost of gas
(4)	Actual cost of acquiring supply		474,894	Lines 1 + 2 + 3
(5)	Cost of system gas at uniform price	3,132,597	429,079	Cost based on the uniform price of \$3.615/GJ or 13.70 ¢/m^3 (Table 5.2)
(6)	Seasonal cost to be transferred prior to adjustment for savings related to operational flexibility		45,815	Line 4 – line 5
(7)	Adjustment for supply savings related to operational flexibility		5,200	R-3867-2013, Gaz Métro-5, Document 12, section 5.3, table 19
(8)	Total seasonal cost to be transferred		52,511	Line 6 + line 7

After applying the proposed method, the transfer from supply to load-balancing would increase from \$43.3M to \$45.8M. With this approach, the cost for the entire supply of system gas sold would not include seasonal costs.

The seasonal cost will have to take into account the adjustment for supply savings related to operational flexibility, as explained in Section 6.2.3 of exhibit Gaz Métro-5, Document 12 in this file. For this example, the savings amount was taken from Table 19 of this exhibit. After taking all of these elements into consideration, the transfer would have been \$52.5M for the 2018–2019 fiscal year.

As per the decision made by the Régie,[2] the seasonal cost to be transferred to load-balancing cannot be negative or else there would be no transfer.

To summarize, Énergir proposed a new simplified method intended to be a more precise way of calculating the annual cost to be transferred from supply to load-balancing. The new method has two advantages:

- It is simpler, because the functionalization method uses an average per-unit cost, which eliminates the need to make monthly purchase volumes uniform;
- It is more representative of cost causation, as it takes into account the total cost charged to the supply service and more precisely determines the portion of supply costs linked to seasonal costs to be transferred to load-balancing.

[2] D-2015-177, paragraph 92.

APPENDIX 6

INDEX OF ALLOCATION FACTORS FOR SUPPLY, TRANSPORTATION AND LOAD-BALANCING COSTS

TABLE OF CONTENTS

BACKGROUND

The allocation factors for supply, transportation and load-balancing costs are set out in this document. The following information is provided for each of the factors:

- the definition;
- the determination, i.e. a description of the inputs used and the method of calculating the factor;
- the application, i.e. the cost items allocated using the factor;
- references in support of the above.

For each of the factors, the application is provided for the current cost allocation study. Subsections have been added for cases where the current cost allocation and proposed allocation define and determine the factor differently.

The current allocation section provides the methods used at the time the cost of service allocation study was filed for the 2020-2021 Rate Case.[1]

It should be noted that this index does not contain the allocation factors for the C&T system service, as no changes have been proposed to that service as part of the overhaul of the supply, transportation and load-balancing services.

[1] R-4119-2020, B-0092, Energir-Q, Document 13.

FB01F – SUPPLY VOLUMES

DEFINITION

Share of forecast supply volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the forecast supply volumes for each rate and rate level by the total volumes forecast. These volumes include volumes withdrawn from the system gas service, the fixed price supply service and the direct purchase service with transfer of ownership. These volumes do not include make-up gas.

APPLICATION

Supply costs

- Supply

REFERENCE

D-2002-196; D-2003-180

FB05EF – DISTRIBUTION OF SUPPLY INVENTORY VOLUMES

DEFINITION

Evaluation of the differential between average daily winter consumption (parameter **W**) and average daily annual consumption (parameter **A**) for supply volumes according to each customer’s consumption profile for the previous year, as forecast in the budget.

DETERMINATION

The share is calculated by taking the difference between the winter average and the forecast annual average for each rate and rate level and dividing it by the total difference between the forecast winter average and the forecast annual average. The forecast winter and annual averages, which are used to determine the allocation factor, reflect only system gas customers, fixed-price supply customers and customers of the supply service with transfer of ownership. The value of each rate and rate level is greater than or equal to 0.

APPLICATION

Current allocation

Supply rate base

- Inventory
  - Gas in inventory – Line Pack
  - LNG
  - Dawn underground storage (Enbridge Gas)
  - Intragaz – Saint-Flavien
  - Intragaz – Pointe-du-Lac
- Unamortized costs

Proposed allocation

No costs allocated using the FB05EF factor

REFERENCE

D-2002-196; D-2003-180

FB07E – SUPPLY REVENUES

DEFINITION

Share of forecast supply revenues in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the forecast supply revenues from customers for each rate and rate level by the total supply revenues forecast.

APPLICATION

Current allocation

Supply rate base

- Working capital
  - Lead-lag studies

Supply revenues

- Supply

Proposed allocation

Supply revenues

- Supply

REFERENCE

D-2002-196; D-2003-180; R-3867-2013

FB07INVF – REVENUES FROM RETURN PORTION ON GAS SUPPLY INVENTORY ADJUSTMENT

DEFINITION

Share of revenues from the return portion on gas supply inventory adjustment according to the budget forecast.

DETERMINATION

The share is calculated by dividing the forecast revenues from customers of the gas supply inventory adjustment service for each rate and rate level by the total revenues forecast. Revenues are prorated to the consumption profile forecast in the budget (FB05EF).

APPLICATION

Current allocation

Supply revenues

- Inventory maintenance

Proposed allocation

No costs allocated using the FB07INVF factor

REFERENCE

D-2002-196; D-2003-180

BASETARF – SUPPLY RATE BASE

DEFINITION

Share of forecast total costs of the supply rate base for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor calculated by dividing the sum of the costs that make up the supply rate base allocated to customers in each rate and rate level divided by the total supply costs forecast.

APPLICATION

Current allocation

Supply costs

- Return on rate base

Proposed allocation

No costs allocated using the BASETARF factor

REFERENCE

G-429, D-2002-196; D-2003-180

REVNETF – NET SUPPLY REVENUES

DEFINITION

Share of forecast net supply revenues for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor determined by calculating the difference between:

- total supply revenues as assigned by the cost allocation study; and
- cost of supply gas.[2]

APPLICATION

Current allocation

Supply rate base

- Working capital
  - Lead-lag tax

Supply costs

- Income tax related to the rate base

Proposed allocation

No costs allocated using the REVNETF factor

REFERENCE

G-429; D-90-44; D-2002-196; D-2003-180

[2] Previously, total supply revenues were also net of the tax expense on the capital portion attributed to supply for each rate and rate level. The capital tax no longer exists.

FB01T – Transportation volumes

Definition

Share of forecast transportation volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

Determination

Current allocation

The share is calculated by dividing the forecast transportation volumes for each rate and rate level by the total volumes forecast. These volumes do not include volumes distributed to customers who provide their own transportation service or who procure their supply on the distributor's territory.

Proposed allocation

The share is calculated by dividing the forecast transportation volumes for each rate and rate level by the total volumes forecast. These volumes do not include volumes distributed to customers who provide their own transportation service, volumes distributed to customers who procure their supply on the distributor's territory and make-up gas service volumes.

Application

Current allocation

Transportation costs

- All transportation costs except Champion Pipeline costs
- Amortization of deferred charges and intangible assets

Proposed allocation

Transportation rate base

- Working capital
  - Lead-lag study
  - Lead-lag tax
- Unamortized costs

Transportation costs

- All transportation costs except Champion Pipeline and CMG costs
- Amortization of deferred charges and intangible assets
- Income tax

Reference

D-2002-196, R-3867-2013

FB01TN – Northern zone transportation volumes

Definition

Share of forecast Northern zone transportation volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

Determination

The share is calculated by dividing the forecast Northern zone transportation volumes for each rate and rate level by the total volumes forecast. These volumes do not include volumes distributed to customers who provide their own transportation service or who procure their supply on the distributor's territory.

Application

Current allocation

Transportation costs

- Transportation fees
    - Champion Pipeline

Proposed allocation

No costs allocated using the FB01TN factor

Reference

D-2002-196

FB01DN – NORTHERN ZONE DISTRIBUTION VOLUMES

DEFINITION

Share of forecast Northern zone distribution volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the forecast Northern zone distribution volumes for each rate and rate level by the total volumes forecast. These volumes do not include volumes distributed to customers who provide in the Northern zone of the distributor's territory and make-up gas service volumes.

APPLICATION

Current allocation

No costs allocated using the FB01DN factor

Proposed allocation

Transportation costs

- Transportation
    - Champion Pipeline

REFERENCE

D-2002-196, D-2020-047, R-3867-2013

FB05ET – ALLOCATION OF TRANSPORTATION INVENTORY VOLUMES

DEFINITION

Evaluation of the differential between average daily winter consumption (parameter **W**) and average daily annual consumption (parameter **A**) for transportation volumes according to each customer's consumption profile for the previous year, as forecast in the budget.

DETERMINATION

The share is calculated by taking the difference between the winter average and the forecast annual average for each rate and rate level and dividing it by the total difference between the winter average and the annual average. The forecast winter and annual averages, which are used to determine the allocation factor, only take into account customers of the distributor's transportation service. The value of each rate and rate level is greater than or equal to 0.

APPLICATION

Current allocation

Transportation rate base

- Inventory
    - Gas in inventory – Line Pack
    - LNG
    - Intragaz – Saint-Flavien
    - Intragaz – Pointe-du-Lac
- Unamortized costs

Proposed allocation

No costs allocated using the FB05ET factor

REFERENCE

D-2002-196

FB07T – TRANSPORTATION REVENUES

DEFINITION

Share of forecast transportation revenues in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

Current allocation

The share is calculated by dividing the forecast transportation revenues from customers for each rate and rate level by the total transportation revenues forecast.

Proposed allocation

The share is calculated by dividing the forecast transportation revenues from customers for each rate and rate level by the total transportation revenues forecast. These revenues do not include forecast make-up gas revenues.

APPLICATION

Current allocation

Transportation rate base

- Cash and materials
    - Lead-lag studies

Transportation revenues

- Transportation

Proposed allocation

Transportation revenues

- Transportation (including Champion Pipeline)

REFERENCE

D-2002-196; R-3867-2013

FB07INVT – REVENUES FROM RETURN PORTION ON TRANSPORTATION INVENTORY ADJUSTMENT

DEFINITION

Share of revenues from the return portion on transportation inventory adjustment according to the budget forecast.

DETERMINATION

The share is calculated by dividing the forecast revenues from customers of the transportation inventory adjustment service for each rate and rate level by the total revenues forecast. Revenues are prorated to the consumption profile forecast in the budget (FB05ET).

APPLICATION

Current allocation

Transportation revenues

- Inventory maintenance

Proposed allocation

No costs allocated using the FB07INVT factor

REFERENCE

D-2002-196

GAC – COMPETITIVE MAKE-UP GAS (DIRECT ALLOCATION)

DEFINITION

Share of forecast competitive make-up gas ("GAC") contract transportation revenues in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

This factor also includes forecast transportation costs generated by the GAC contracts in the Rate Case, because these costs are directly charged to the customers bound to such contracts.

DETERMINATION

The share is calculated by dividing the forecast revenues (or costs) of each rate and rate level by the total revenues (or costs) forecast.

When positioned within the rate levels, GAC customers fall under Category A of the interruptible rate as per forecast annual volumes.

APPLICATION

Current allocation

No costs allocated using the GAC factor

Proposed allocation

<u>Transportation revenues</u>

- GAC

<u>Transportation costs</u>

- GAC

REFERENCE

R-3867-2013

BASETART – TRANSPORTATION RATE BASE

DEFINITION

Share of forecast total costs of the transportation rate base for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor calculated by dividing the sum of the costs that make up the transportation rate base allocated to customers in each rate and rate level by the total transportation costs forecast.

APPLICATION

Transportation costs

- Return on rate base

REFERENCE

G-429; D-2002-196

REVNETT – NET TRANSPORTATION REVENUES

DEFINITION

Share of forecast net transportation revenues in each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor determined by calculating the difference between:

- total transportation revenues as assigned by the cost allocation study; and
- transportation costs.[3]

APPLICATION

Transportation rate base

- Working capital
  - Lead-lag tax

Transportation costs

- Income tax

Proposed allocation

No costs allocated using the REVNETT factor

REFERENCE

G-429; D-90-44; D-2002-196

[3] Previously, total transportation revenues were also lowered by the tax expense on the capital portion attributed to transportation for each rate and rate level. The capital tax no longer exists.

FB01E – LOAD-BALANCING VOLUMES

DEFINITION

Share of forecast load-balancing volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

Current allocation

The share is calculated by dividing the forecast load-balancing volumes for each rate and rate level by the total volumes forecast. These volumes do not include those distributed to customers who do not use the load-balancing service.

Proposed allocation

The share is calculated by dividing the forecast load-balancing volumes for each rate and rate level by the total volumes forecast. These volumes do not include volumes distributed to customers who do not use the load-balancing service and make-up gas service volumes.

APPLICATION

Current allocation

No costs allocated using the FB01E factor

Proposed allocation

Load-balancing rate base

- Inventory
  - Dawn underground storage (Enbridge Gas)
- Unamortized costs
  - Fixed costs – Dawn storage (Enbridge Gas)

Load-balancing costs

- Operational flexibility

[…]

- Income tax – "operational flexibility" portion

REFERENCE

D-2002-196, R-3867-2013

FB05E (CURRENT) – LOAD BALANCING – "SPACE" FACTOR

DEFINITION

Evaluation of the differential between average daily winter consumption (parameter **W**) and average daily annual consumption (parameter **A**) for load-balancing volumes according to each customer's consumption profile for the previous year, as forecast in the budget.

DETERMINATION

The share is calculated by taking the difference between the winter average and the forecast annual average for the previous year for each rate and rate level and dividing it by the total difference between the winter average and the annual average.

The forecast winter and annual averages used to determine the allocation factor only take into account customers of the distributor's load-balancing service. The evaluation period for the winter average begins on November 1 and ends on March 31 of the following year. For customers with interruptible service, parameters **A** and **W** are modified.

APPLICATION

Current allocation

Load-balancing rate base

- Fixed assets
    - Storage – liquefaction – space
- Inventory
    - Enbrige Gas underground storage (space)
    - Intragaz – Saint-Flavien
- Unamortized costs
    - Fixed costs – Saint-Flavien storage
    - Cushion gas transport costs – Saint-Flavien
    - Fixed costs – Enbridge Gas underground storage (space)
    - Recovery – temperature stabilization accounts
    - Recovery – revenue shortfall

Load-balancing costs

- Underground gas storage at Dawn (space)
- STS – Dawn/Parkway/Franchise (space)
- SH service – Dawn/Franchise
- SH service – Dawn/Parkway/Franchise
- Underground gas storage in Saint-Flavien
- TQM

  - Sale of SH transportation tools
  - Intragaz (space)
- Other costs
  - Transportation costs for purchases at Dawn (space)
- Tool optimization
  - Gas swaps
  - Loan of space
  - Transportation
- Amortization of deferred costs
  - Cushion gas transport
  - Pass-on storage space costs
  - Revenue shortfall and temperature stabilization (shortfalls/overpayments)
- Postponed rate changes
  - Space costs

Proposed allocation

Refer to factor FB05E (proposed).

REFERENCE

G-429; D-97-47; D-99-11; D-2000-34; D-2005-171

FB05E (PROPOSED) – LOAD-BALANCING PROFILE

DEFINITION

Evaluation of the differential between peak winter consumption (parameter **P**) and annual average daily consumption (parameter **A**) applied to the load-balancing volumes as forecast in each customer's budget.

DETERMINATION

The share is calculated by taking the percentage difference between the winter peak and the annual average of the previous year, applied to the forecast volumes for each rate and rate level and dividing it by the total difference between the winter peak and the annual average. The following formula is used:

$$\frac{(\mathrm{P}-\mathrm{A})}{A} * Load\ balancing\ volume\ as\ forecast\ in\ customer's\ budget$$

The forecast winter peak and annual average, which are used to determine the allocation factor, only take into account customers of the distributor's load-balancing service. The evaluation period for the winter peak begins on December 1 and ends on the last day of February of the following year.

Evaluation of the differential between peak winter consumption (parameter **P**) and annual average daily consumption (parameter **A**) applied to the load-balancing volumes as forecast in each customer's budget.

APPLICATION

Current allocation

Refer to factor FB05E (current).

Proposed allocation

<u>Load-balancing rate base</u>

- Fixed assets
- Working capital
- Inventory
    - Gas in inventory – Line Pack
    - LNG
    - Intragaz – Saint-Flavien
    - Intragaz – Pointe-du-Lac
- Unamortized costs
    - Gas related costs
    - Liquefaction costs
    - Fixed costs – Saint-Flavien storage
    - Cushion gas transport costs – Saint-Flavien storage

<u>Load-balancing costs</u>

- Load-balancing
  - Seasonal load-balancing costs
- Amortization expenses – fixed assets
- Amortization of deferred charges and intangible assets
- Income tax – “seasonal” portion
- Cost of using the LSR plant reimbursed by the customer GM LNG

REFERENCE

G-429; D-97-47; D-99-11; D-2000-34; D-2005-171; R-3867-2013

FB05P – LOAD-BALANCING – "PEAK" FACTOR

DEFINITION

Evaluation of the differential between peak daily winter consumption (parameter **P**) and average daily winter consumption (parameter **W**) for load-balancing volumes according to each customer's consumption profile for the previous year, as forecast in the budget.

DETERMINATION

The share is calculated by taking the difference between the winter peak and the forecast winter average for the previous year for each rate and rate level and dividing it by the total difference between the winter peak and the winter average.

The forecast winter peak and winter average, which are used to determine the allocation factor, only take into account customers of the distributor's load-balancing service. The evaluation period for the winter average and winter peak begins on November 1 and ends on March 31 of the following year. For customers with interruptible service, parameters **W** and **P** are modified.

APPLICATION

Current allocation

Load-balancing rate base

- Fixed assets
  - Storage – liquefaction – peak
- Inventory
  - Enbridge Gas underground storage (peak)
  - LNG
- Unamortized costs
  - Liquefaction costs
  - Fixed costs – Enbridge Gas underground storage (peak)

Load-balancing costs

- Load-balancing
  - Underground gas storage at Dawn (peak)
  - STS – Dawn/Parkway/Franchise (peak)
  - SH service – Dawn/Franchise (peak)
  - Peak service
  - Liquefied natural gas (LSR)
  - Intragaz (peak)

- Other costs
    - Peak tool optimization
    - Transportation costs for purchases at Dawn (peak)
- Amortization of deferred costs
    - Pass-on peak storage costs
- Postponed rate changes
    - Peak fees
- Amortization of fixed assets
- Cost of using the LSR plant reimbursed by the customer GM LNG

Proposed allocation

No costs allocated using the FB05P factor

REFERENCE

G-429; D-97-47; D-99-11; D-2000-34; D-2005-171

FB07E-E – LOAD-BALANCING REVENUES – SPACE

DEFINITION

Share of forecast load-balancing volumes related to space in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the forecast revenues related to space from customers for each rate and rate level by the total forecast revenues related to space.

APPLICATION

Current allocation

Load-balancing rate base

- Cash and materials
    - Lead-lag studies – space portion

Load-balancing revenues

- Load-balancing – space portion

Proposed allocation

No costs allocated using the FB07E-E factor

REFERENCE

D-2002-196; D-2003-180

FB07E-P – Load-balancing revenues – Peak

Definition

Share of forecast load-balancing revenues related to peak in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

Determination

The share is calculated by dividing the forecast revenues related to peak from customers for each rate and rate level by the total forecast revenues related to peak.

Application

Current allocation

Load-balancing rate base

- Cash and materials
    - Lead-lag studies – peak portion

Load-balancing revenues

- Load-balancing – peak portion

Proposed allocation

No costs allocated using the FB07E-P factor

Reference

D-2002-196; D-2003-180

FB07ES – LOAD-BALANCING REVENUES – SEASONAL

DEFINITION

Share of forecast load-balancing revenues allowing for the recovery of seasonal costs in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the seasonal portion of revenues from customers for each rate and rate level by the total forecast seasonal portion of revenues.

APPLICATION

Current allocation

No costs allocated using the FB07ES factor

Proposed allocation

Load-balancing revenues

- Load-balancing – seasonal portion

REFERENCE

D-2002-196; D-2003-180; R-3867-2013

FB07PT – LOAD-BALANCING REVENUES FOR ALL

DEFINITION

Share of forecast load-balancing revenues allowing for the recovery of operational flexibility costs and costs not required for customer needs in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

DETERMINATION

The share is calculated by dividing the "for all" portion of revenues from customers for each rate and rate level by the total forecast "for all" portion of revenues.

APPLICATION

Current allocation

No costs allocated using the FB07PT factor

Proposed allocation

Load-balancing revenues

- Load-balancing – “For all” portion

REFERENCE

D-2002-196; D-2003-180; R-3867-2013

BASETAREE – LOAD-BALANCING RATE BASE – SPACE

DEFINITION

Share of forecast total costs of the load-balancing rate base related to space for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor calculated by dividing the sum of the costs related to space that make up the load-balancing rate base allocated to customers in each rate and rate level by the forecast total costs related to space.

APPLICATION

Current allocation

Load-balancing costs

- Return – space portion

Proposed allocation

No costs allocated using the BASETAREE factor

REFERENCE

G-429; D-2002-196; D-2003-180

BASETAREP – LOAD-BALANCING RATE BASE – PEAK

DEFINITION

Share of forecast total costs of the load-balancing rate base related to peak for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor calculated by dividing the sum of the costs related to peak that make up the load-balancing rate base allocated to customers in each rate and rate level by the forecast total costs related to peak.

APPLICATION

Current allocation

Load-balancing costs

- Return – peak portion

Proposed allocation

No costs allocated using the BASETAREP factor

REFERENCE

G-429; D-2002-196; D-2003-180

BASETARE – LOAD-BALANCING RATE BASE

DEFINITION

Share of forecast total costs of the load-balancing rate base for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor calculated by dividing the sum of the costs that make up the load-balancing rate base allocated to customers in each rate and rate level by the total load-balancing costs forecast.

APPLICATION

Current allocation

No costs allocated using the BASETARE factor

Proposed allocation

Load-balancing costs

- Return on rate base

REFERENCE

G-429; D-2002-196; D-2003-180; R-3867-2013

REVNETEE – NET LOAD-BALANCING REVENUES – SPACE

DEFINITION

Share of forecast net load-balancing revenues related to space for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor determined with the following calculation:

- total load-balancing revenues related to space as assigned by the cost allocation study
- minus fixed load-balancing costs related to space
- minus amortization expenses for load-balancing related to space[4]

APPLICATION

Current allocation

Load-balancing rate base

- Working capital
    - Lead-lag tax – space portion

Load-balancing costs

- Income tax – space portion

Proposed allocation

No costs allocated using the REVNETEE factor

REFERENCE

G-429; D-90-44; D-2002-196; D-2003-180

[4] Previously, total load-balancing revenues related to space were also lowered by the tax expense on the capital portion attributed to load-balancing related to space for each rate and rate level. The capital tax no longer exists.

REVNETEP – NET LOAD-BALANCING REVENUES – PEAK

DEFINITION

Share of forecast net load-balancing revenues related to peak for each rate and rate level in the Rate Case.

DETERMINATION

Derivative factor determined with the following calculation:

- total load-balancing revenues related to peak as assigned by the cost allocation study
- minus fixed load-balancing costs related to peak
- minus amortization expenses for load-balancing related to peak[5]

APPLICATION

Current allocation

Load-balancing rate base

- Working capital
    - Lead-lag tax – peak portion

Load-balancing costs

- Income tax – peak portion

Proposed allocation

No costs allocated using the REVNETEP factor

REFERENCE

G-429; D-90-44; D-2002-196; D-2003-180

[5] Previously, total load-balancing revenues related to peak were also lowered by the tax expense on the capital portion attributed to load-balancing related to peak for each rate and rate level. The capital tax no longer exists.

FB01D – Distribution volumes

Definition

Share of forecast distribution volumes in the Rate Case, attributable to each rate and rate level, expressed as a percentage.

Determination

The share is calculated by dividing the forecast distribution volumes for each rate and rate level by the total volumes forecast. Make-up gas volumes are not included.

No volume was allocated to receipt service customers (D_R) because all costs are directly allocated to those customers.

Application

Current allocation

Distribution costs

- Operating expenses
  - Administrative services and general expenses
    - Regulation, Accounting, Public and Governmental Affairs, Demand Forecast
- Distribution costs
  - Gas lost in the network
  - Delivery station, Gas delivery service
- Depreciation expense for deferred charges
  - Deferred charges
    - Lost gas level
  - Miscellaneous
    - Fees to the Régie
- Taxes and fees
  - Fees to the Régie
    - Fees to the Régie building/énergie

Distribution pricing basis

- Unamortized costs
  - Unamortized costs – other
    - Leveling recovery of lost gas
    - Fees to the Régie

Proposed allocation

Distribution costs

- Operating expenses
  - Administrative services and general expenses
    - Regulation, Accounting, Public and Governmental Affairs, Demand Forecast
- Distribution costs
  - Gas lost in the network
  - Delivery station, Gas delivery service
- Depreciation expense for deferred charges
  - Deferred charges
    - Lost gas level
  - Miscellaneous
    - Fees to the Régie
- Taxes and fees
  - Fees to the Régie
    - Fees to the Régie building/énergie

Distribution pricing basis

- Unamortized costs
  - Unamortized costs – other
    - Leveling recovery of lost gas
    - Fees to the Régie

Balancing Costs

- Costs not required for customer needs

- Income tax – portion « not required for customer needs »

DEPENDENT ALLOCATION FACTORS

- CASEP
- FB09CL
- FS27
- FS28
- FS31

REFERENCE

G-429, R-3867-2013

APPENDIX 7

FOLLOW-UP ON DECISION D-2016-126

TABLE OF CONTENTS

A. BACKGROUND

This document brings together and addresses some of the follow-ups requested by the Régie de l'énergie (the Régie) in its decision D-2016-126. For your information, Énergir, L.P. (Énergir) has not updated the responses to the follow-ups contained in this document since the original filing in January 2017, except for Table 7.3 and a portion of section D.2.3 regarding meters.

B. BENCHMARKING

In paragraph 72 of its decision D-2016-126, the Régie ordered the Distributor to submit additional evidence regarding the:

> "*[72]* […] *benchmarking of the methods of allocating the supply, transportation and load-balancing costs used by other North American gas distributors;* […]" [Translation]

The Régie later continued by indicating it felt that, in addition to allocation, this benchmarking should also focus on the pricing of those same services:

> "*[74]* […] *benchmarking of the pricing of the supply, transportation and load-balancing services used by other North American gas distributors;* […]" [Translation]

Énergir therefore turned to the American Gas Association (AGA) and the Canadian Gas Association (CGA) to obtain the desired information.

The result of these surveys is presented in the following tables.

Table 7.1

Main allocation factors by service

Distributor	Supply	Transportation	Load balancing
Énergir	Volume	Volume	Annual, winter and peak averages
Pacific Northern Gas	Volume	Volume and distance	Capacity
FortisBC	Volume	Capacity	Capacity
AltaGas	N/A	Capacity	Capacity
SaskEnergy	Volume	Capacity	Volume
Enbridge Gas Distribution	Volume	Volume	Annual, winter and peak averages
Delta Natural Gas	Volume	Volume	N/A
Questar Gas	Volume and peak	Volume and peak	Volume and peak
ENSTAR Natural Gas	Volume	3-day volume and peak	N/A
Xcel	Volume	Capacity	Volume

Note that “peak” refers to the maximum daily consumption observed. When the term “capacity” is used, the respondents did not specify if it referred to pre-established capacity or a capacity derived from the consumption history.

The following table indicates the main pricing factor by service. This factor is underlined when it differs from the main allocation factor. Also, the “Services” column indicates whether the distribution and transportation services are bundled or not.

Table 7.2

Main pricing factors by service

Distributor	Supply	Transportation	Load balancing	Services
Énergir	Volume	Volume	Annual, winter and peak averages	Unbundled
Pacific Northern Gas	Volume	**Volume**	**Volume**	Bundled
FortisBC	Volume	Capacity	Capacity	Bundled
AltaGas	N/A	Capacity	Capacity	Bundled
SaskEnergy	Volume	Capacity	Volume	Bundled
Enbridge Gas Distribution	Volume	Volume	Annual, winter and peak averages	Unbundled
Delta Natural Gas	Volume	**Capacity**	N/A	Unbundled
Questar Gas	Volume and peak	Volume and peak	Volume and peak	Unbundled
ENSTAR Natural Gas	Volume	Annual and peak averages	N/A	Unbundled
Xcel	Volume	Capacity	Volume	Depends on the state

While the application of the supply, compression and transportation services is universal, Énergir notes that such is not the case for load-balancing. In fact, load-balancing, as Énergir defines it, is included in the supply service by the other distributors. Load-balancing for the other distributors relates more to the volume imbalances that Énergir treats in the supply service. Moreover, the load-balancing service is not unbundled by any of the respondent distributors.

C. HOURLY MANAGEMENT OF THE NETWORK

In decision D-2016-126, paragraph 74, the Régie asked Énergir to analyze the:

> "*[74]* […] *relationships between the daily management of the nominations and the hourly management of the network:*

- *usefulness of asking customers to displace hourly consumption amounts in order to limit the daily peak requirements or limit the use of advanced tools such as liquefied natural gas (LNG);* […]" [Translation]

During the 2015 Rate Case, Énergir presented the limitations of hourly interruptions in optimizing gas *supplies*[1]. Énergir explained that:

- The standard in the North American gas industry is daily management of supplies (North American Energy Standards Board - NAESB);
- The hourly nomination windows allow for balancing the deliveries on a daily basis: deliveries are adjusted several times during the day so their total equals the total withdrawals;
- The tracking done by supply-tool providers is daily: penalties are incurred for overly large daily imbalances;
- Énergir's hourly management of the network does not concern the supply services but rather the distribution service; and
- Énergir's Ontario peers (Union Gas and Enbridge Gas Ontario) plan their supply on a daily basis.

Furthermore, the transportation contracts signed with the supplier TCPL specify the maximum hourly withdrawal volume. This maximum hourly withdrawal volume is equal to 5% of the daily capacity contracted, i.e. a level slightly higher than a uniform hourly volume of 1/24th (or 4.2% of the daily capacity contracted). Beyond the 5% threshold, TCPL cannot guarantee the pressure level in the pipelines. However, this operational constraint is not an issue in the management of supplies, at present.

The current daily planning is done to ensure that each winter day is serviced given the daily characteristics of the tools, but independently of the hourly consumption profile for each of the days. Taking into account the distribution of the consumption during a day and the hourly characteristics of the storage tools, conditions to be satisfied by the supply plan are added. Hourly management of the supplies would not enable a reduction in the costs of the supply plan beyond

[1] R-3879-2014, B-0263, Gaz Métro-7, Document 4, p. 15 and A-0056, pp. 56 to 62.

the optimization that is achieved by daily management of the supplies. This is what the following paragraphs demonstrate.

The following example shows that the transportation capacities cannot be reduced by planning the supplies hourly since the daily peak must also be supplied:

- The peak-day demand is 1,000 GJ/day;
- The maximum hourly demand is 45 GJ/hr, or 1,080 GJ/day when calculated over 24 hours; and
- The maximum hourly volume for the supply tools, according to TCPL's rules, is 1/20th of the daily capacity contracted, or 50 GJ/hr.

If the supplies were planned hourly, and the sole objective was to meet the hourly peak demand, the capacities contracted would be based on that volume. As such, it would be necessary to ensure that 1/20th of the capacities contracted equalled 45 GJ/hr. However, this would represent a daily capacity of 900 GJ/day, which is less than the total peak-day demand of 1,000 GJ/day. Since the distributor must be able to meet the daily peak, it cannot contract less than 1,000 GJ/day.

In a case where the maximum hourly demand were higher, for example 55 GJ/hr, the maximum hourly volume of the supplies of 50 GJ/hr would not have been enough to meet the demand. It would have therefore been necessary to contract a capacity of 1,100 GJ/day in order to withdraw 55 GJ/hr under TCPL's guaranteed minimum pressure. Énergir has determined that it does not need to protect itself against that possibility for the moment.

As for the advanced tools, such as the LSR plant, the situation is somewhat different. For hourly management of the tools to be useful, it would need to help reduce erosion. However, to reduce the erosion of the storage sites, the daily demand has to be decreased. So distributing consumption during the day does not affect the level of erosion unless the daily demand is reduced. For example, the tool erosion is the same if a customer withdraws its entire daily volume during the same hour or uniformly during the day.

Énergir concludes that it would not be useful to ask customers to displace their hourly consumption, within the same day, in order to reduce the costs of the supply plan. In fact, the supply tools are purchased in advance and in that context, hourly management would not enable a reduction in the peak capacities contracted or the use of advanced tools beyond the optimization achieved through daily management of the supplies.

Énergir understands that the scope of the follow-up requested by the Régie in paragraph 74 could exceed the supply services provided by Énergir. The text of the decision refers to “hourly management of the network.” While Phase 2 of this case does not concern its distribution network, Énergir understands that the Régie might wonder about the possibilities of optimizing it. The distributor wishes to remind the Régie that the distribution network’s rate structure will be examined in Phase 4 of this case.

D. ADVANCED METERING INFRASTRUCTURE

The Régie also asked Énergir to examine the possibilities offered by installing an advanced metering infrastructure[2]. However, it is important to bear in mind, as mentioned in the previous section, that Phase 2 of this rate case concerns the supply services. So the possibilities offered by advanced metering addressed here have to do only with the supply, transportation and load-balancing services. The possibilities for optimizing the distribution network will be addressed during Phase 4.

D.1 ADVANCED METERING INSTRUMENTS

During Phase 1 of this rate case, Énergir presented the four types of meter it uses: diaphragm, rotary, turbine and ultrasonic. Schedule 2 of exhibit B-0023, Gaz Métro-2, Document 1 describes each type of meter. All of these meters are able to measure consumption hourly. The constraint in acquiring real-time hourly or daily data has more to do with the types of meter reading.

[2] D-2016-126, paragraph 74.

Meter reading is currently done in three different ways: pedestrian, radiometry and telemetry.

Table 7.3
Number of meters by type of reading

Type of reading	June 2020
Pedestrian	675
Radiometry	229,464
Telemetry	968

<u>Pedestrian reading</u>

Pedestrian meter reading is done manually by an Énergir employee. The employee directly reads the meter. This outdated method is being gradually replaced by radiometry. However, pedestrian meter reading is useful when there is a deficiency with the other reading methods.

<u>Radiometry</u>

This method of meter reading is done by means of radiofrequency (RF) transmitters. The information is acquired via signals transmitted by the device when an Énergir vehicle passes close by. The vehicles periodically travel routes to take customer meter readings at least once per billing cycle. If the data is not collected during a billing cycle, the volume withdrawn is estimated and then corrected the following month.

There are two types of transmitters. The first kind remains in stand-by mode between queries from the meter-reading vehicle. This device does not store any daily or hourly consumption data. The second type of device transmits a signal at regular intervals and can store hourly readings for the 40 days preceding communication with the meter-reading vehicle. This data could make it possible to precisely reconstruct a customer's consumption for a given month instead of using projected volumes for billing purposes. For example, for a billing cycle beginning August 15 and ending September 15, this device could precisely indicate the supply volumes for the month of August.

Additionally, fixed antenna network technology enables real-time data transmission, but is not used by Énergir. This type of infrastructure is comprised of NANs (Neighborhood Area Networks) in which meters are interconnected and WANs (Wide Area Networks) serviced by collectors that agglomerate the data of nearby meters and by routers that enable wider geographic coverage. The information is transmitted from the collectors by cellular or satellite telecommunication. Hydro-Québec's remote meter reading project uses this technology and required installing collectors and routers on existing communication towers, in the facilities or on the power distributor's poles. If Énergir wanted to gather real-time data, this is likely the technology it would use.

Telemetry

With telemetry, meter data is transmitted over the customer's telephone line, over a telephone line installed by Énergir or by cellular telephone. With a telephone call, Énergir is able to obtain the hourly or daily consumption data for the past seven days, depending on the parameters set.

Only rate D_4 and rate D_5 customers, rate combination D_3 and D_5 customers, and certain customers in remote regions have their meter read by telemetry.

D.2 Supply tool optimization

The Régie asked Énergir to analyze the:

> "[…] *possibilities offered by installing an advanced metering infrastructure* [for the] *optimization of the supply tools and management of the network using hourly or daily readings processed in real time* […]."[3] [Translation]

Énergir has analyzed this matter by distinguishing between the "gas supplies" aspect and the "pricing" aspect.

With respect to supplies, advanced metering makes it possible to gather more detailed customer-profile data. This better quality data could improve the forecasting models used to acquire the supply tools. Énergir notes that it already has the hourly consumption profile for the overall demand because it ensures the supply of its network by section in real time. This profile

[3] D-2016-126, paragraph 74.

enables Énergir to adjust its supplies based on the total needs projected for the gas day, without requiring customers' individual information in real time.

In terms of pricing, advanced metering makes it possible to observe the parameters of a consumption profile more precisely, better reflecting the costs on the customer's bill, and therefore send a better price signal. This type of pricing encourages lower peak consumption. In this section, Énergir also examines the relevance of managing demand on an hourly basis and in real time, applying a personalized load-balancing rate to all customers, and considering the observed peak rather than the estimated one.

D.2.1 Potential improvement of the forecasting models

Daily data are used in the supply plan to forecast the peak-day consumption.

The advanced metering infrastructure would make it possible gather more detailed consumption-profile data for each rate class. This better quality data could improve the demand forecasting models used to acquire the supply tools.

D.2.2 Hourly demand management

As explained in section B, the hourly consumption peak does not currently generate any additional supply cost relative to the daily peak. Even if the information were available for certain customers, it would not be useful to consider it in pricing the supply services.

Since the supply plan is always done a *priori* (for Énergir and for the other gas distributors[4]), real-time rate incentives would be of no use with respect to supplies.

Furthermore, the daily planning of gas supplies is always done a *priori* with the goal of ensuring that the anticipated needs are met by the tools contracted. So real-time pricing is not useful in managing supplies.

[4] R-3879-2014, B-0263, Gaz Métro-7, Document 4, p. 11.

D.2.3 Use of the observed peak for the load-balancing rate

At present, most customers are subject to an average price for the load-balancing service. As indicated in section 3.5.4 of exhibit Gaz Métro-5, Document 14, the access threshold for the personalized load-balancing rate is related more to an overall rate strategy, which will be analyzed during Phase 4 of this case

For customers subject to a personalized load-balancing rate (article 13.1.2.2 of the *Conditions of Service and Tariff*), only those with distribution rate D_4 and distribution rate D_5 and those with rate combination D_3 and D_5 are billed based on a daily meter reading. These readings make it possible to precisely record the consumption peak (parameter “P”). For all other customers, the “P” parameter is estimated using a formula (article 13.1.3.1 of the *Conditions of Service and Tariff*).

That being said, and as mentioned in section 3.5.2 of exhibit Gaz Métro-5, Document 14, the infrastructure needed to record the actual daily peak has been installed on the premises of all personalized-rate customers since 2017. However, aside from the technological constraints, an IT project to allow the daily data to be used for billing will also be required.

Since the vast majority of the customers subject to the personalized rate are billed based on an estimation of their peak-day consumption, considering the actual daily reading in the service pricing would enable a better price signal and have the potential to reduce the peak demand and lower the supply costs. In fact, for the customers without daily readings, the estimated peak is only a projection based on the profile for a customer’s type of heating. During the coldest days, customers without daily readings have no direct incentive to reduce their consumption.

D.3 Optimization of the interruptible services, MGAI and CMG

Once again, as explained in section B, Énergir feels that it is not necessary to manage supplies on an hourly basis. So an interruptible service based on hourly data would be of no use if it is only to limit customers' daily consumption, which is already possible with the current service.

Furthermore, since Énergir plans the supplies before the start of the year, managing interruptions in real time with a price mechanism would not enable a reduction in the tools contracted to meet the demand for all winter days. Énergir thus also rules out the possibility of managing interruptible-service customers' demand in real time.

The same conclusions apply to managing Make-up Gas to Avoid an Interruption (MGAI): without hourly or real-time interruptions, this service would serve no purpose.

For Competitive Make-up Gas (CMG), Énergir contracts additional transportation capacities and bills the cost directly to the customer. With the supply plan being deemed optimized before a CMG customer engages with the distributor, using hourly or real-time measures would not provide any reduction in costs.

However, managing interruptions on an hourly basis could be useful in the case of the distribution network. This element will be analyzed in Phase 4 of this case.