REMOTE READING PROJECT
PHASES 2 AND 3

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Glossary

MOC	Measurement Operations Center
NGM	New Generation Meter
BII	Business, Institutional and Industrial
AMI	Advanced Measurement Infrastructure
k	thousand(s)
LAD	Remote Reading
M$	million(s) of dollars
MDMS	Measurement Data Management System
Opt-out option	Electricity distribution tariffs and conditions relating to an option for installing a meter that does not emit radio frequencies
Regulation	*Regulation on the Conditions and Cases Requiring Authorization from the Energy Authority*
N/A	Not applicable
IT	Information Technologies

Note: The totals in the documents tables are calculated from un-rounded data.

1
. INTRODUCTION

The purpose of the remote reading project ("LAD project") is to install an Advanced Measurement Infrastructure (AMI) and replace 3.75 million in-service meters with new generation meters. The LAD project affects all Hydro-Québec Distribution (the "Distributor") clients, except for high power clients (tariffs L and LG).

With the present request, the Distributor is pursuing phases 2 and 3 of the meter replacement plan and is thus completing the deployment throughout the territory it serves. The work totals $557 million and will be spread from January 2014 to June 2018.

Phases 2 and 3 of the meter replacement plan cover:

- Purchase of new generation meters and telecommunications equipment (collectors and routers);
- Installation and integration in each region of required telecommunication equipment and services;
- Replacement of 2.1 million existing meters with new generation meters;
- Coverage of the installed meters by the MOC for billing purposes.

In its decision D-2012-127[1], the Energy Authority (the "Authority") authorized phase 1 of the LAD project. This phase served to set up an AMI and began the phase 1 meter replacement plan. By October 25, 2013, out of 1.7 million replacements planned for the greater Montréal region[2], almost 760 K new generation meters were installed and read by the MOC. The Distributor expects that the phase 1 costs will be $12.5 million below the cost forecast in case R-3770-2011 and will total $427.9 million[3].

[1] D-2012-127, *Final Decision on the Application for Remote Reading Project Authorization – Phase 1*, 5 October 2012, case R-3770-2011.
[2] Île de Montréal, Laval, towns from the northern crown and a part of the towns from the southern crown (D-2012-127 [R-3770-2011], paragraph 219).
[3] For more detail on the progress of phase 1, see *Remote Reading Project Phase 1 Tracking on September 30, 2013* in document HQD-1, document 2.

The authorization request for LAD project phases 2 and 3 is filed in compliance with Article 73 of the *Law on the Energy Authority* (the “Law”) and the associated regulation.

Some information required under the *Regulation on the Conditions and Cases Requiring Energy Authority Authorization* (the “Regulation”), still valid in the context of the present request, were subject to an in-depth analysis by the Authority and the participants in connection with the LAD project phase 1 authorization[4]. The main items are reviewed in this document. They concern project objectives and justification (section 2), the LAD project economic feasibility study (section 7), expected efficiency savings (section 7.1), impact on the Distributor’s required revenues (section 8), impacts on quality of service (section 9), authorizations required under other laws (section 10) and the principal technical standards applicable to the project (Attachment B). In this respect, the Authority indicated in its decision D-2012-127 that it was satisfied with the Distributor’s evidence and the conclusions of its economic analyses[5].

The other information required to support the request is not different from the items presented in case R-3770-2011, in particular as it involves the deployment strategy, work associated with the project (Sections 3.2 and 3.3), expected project costs and related assumptions (Section 5.1). The Distributor also reports on the main risks associated with the project (Section 6). The present request therefore falls under the continuation of phase 1 under the heading of the meter replacement plan for other regions of Québec served by the Distributor.

In this document, the Distributor presents all the items so that the Authority can “analyze the new required investments [for phases 2 and 3] and judge whether they are useful or necessary in the context of the development of the [LAD] Project.”[6] The Distributor indicates, in Attachment A, the alignment of the information required by the Regulation with the sections of the evidence, and also the pertinent paragraphs from the Authority’s decision D-2012-127.

[4] D-2012-127 (R-3770-2011), paragraphs 1, 4 to 10 and 13.
[5] D-2012-127 (R-3770-2011), paragraphs 314 and 525.
[6] D-2012-127 (R-3770-2011), paragraph 524.

2. PROJECT OBJECTIVES AND JUSTIFICATION

The Distributor indicated that the LAD project has three kinds of objectives[7]:

- Providing for the durability of the embedded base of meters;
- Achieving efficiency improvements coming from automation of consumption reading, just like remote service cut-off and restoration;
- Choosing an evolvable technology through which new services could be offered to clients and network management measures implemented.

In decision D-2012-127[8], the Authority noted that "[t]he aging of the embedded base of meters is an essential factor to be considered in the analysis of the [LAD] Project. Precise measurement and billing of the electricity consumed by its clients are core activities of the Distributor's operations." The LAD project provides for the durability of the base of meters. When authorizing phase 1 of the LAD project, the Authority considered the average age of the existing base of meters and compliance with Measurement Canada measuring standards[9].

In the face of an embedded base of meters which must be renewed, the Distributor chose a technology whose evolvable platform will over time provide for the introduction to the clients of new functionalities or services[10]. In paragraph 238 of its decision D-2012-127, the Authority notes that "[t]he evidence demonstrates that the technology introduced by the [LAD] Project offers the possibility of adding new functionalities at the opportune moment."

The Distributor indicated[11] that these new functionalities will need to address a real need of the clients or the Distributor. All functionality will be examined to demonstrate that it generates benefits for the clients or the Distributor. As appropriate, a specific authorization request will be filed with the Authority.

[7] D-2012-127 (R-3770-2011), paragraphs 15 and 220.
[8] D-2012-127 (R-3770-2011), paragraph 222.
[9] D-2012-127 (R-3770-2011), paragraphs 223 to 226. See also paragraphs 39 to 43.
[10] D-2012-127 (R-3770-2011), paragraphs 20, 239 and 240.
[11] D-2012-127 (R-3770-2011), paragraph 21.

BOX 1: FUNCTIONALITY OUTSIDE THE SCOPE OF THE LAD PROJECT

Since the authorization of LAD project phase 1 by the Authority, the Distributor started work to embed additional functionalities, in particular:

- Starting in 2014, the Distributor plans to implement a tool with which clients can manage their consumption by displaying it in *My Client Space* on the company website.
- In collaboration with the Québec Electricity Research Institute (IREQ), the Distributor developed a technical solution for the purpose of making it easier to detect cases of diversion. The solution is going to be gradually introduced starting in 2014.
- By quickly obtaining precise information on outages, the Distributor would be able to considerably improve their management. When this functionality is implemented, clients will no longer need to call to report an outage. In the meantime, the Distributor developed the algorithm needed for incorporating the AMI data in the Distribution Operation Center (DOC) to improve outage management.

Complying with decision D-2012-127[12], the Distributor will present the progress report for these various projects in connection with an upcoming quarterly review.

Through the LAD project, the Distributor will be able to substantially improve the efficiency of its Reading process activities and of the collection process's service cut-off and restoration activities[13]. Thus recurring annual savings of $81 million will be achieved starting with the 2019 control year[14]. Beyond the impact on the Distributor's efficiency, the LAD project offers clients concrete benefits[15]. Thus, the readers will no longer need to access their clients' properties for reading and for service cut-off and restoration. Client billing is based

[12] D-2012-127 (R-3770-2011), paragraph 532.
[13] D-2012-127 (R-3770-2011), paragraphs 227 to 233.
[14] D-2012-127 (R-3770-2011), paragraphs 44 and 349. The interval, 2018 to 2019, for achieving recurring annual savings of $81 million principally follows from the delay of the bulk deployment and from the revision of the phase 1 deployment schedule.
[15] D-2012-127 (R-3770-2011), paragraphs 65 to 69, 234 and 235.

on actual consumption data and not on estimates as was sometimes the case with electromechanical and first-generation electronic meters.

In paragraph 240 of its decision D-2012-127, the Authority concluded that “[i]t’s therefore a matter of a structural project which could in time be improved by the addition of new functionalities, to the benefit of the Distributor’s clients.”

3. PROJECT DESCRIPTION

3.1. Work for Phase 1

There are two kinds of work to be done following the Authority’s phase 1 authorization[16]:

- Setting up an AMI;
- Installing the telecommunications infrastructure and replacing 1.7 million existing meters.

Under the heading of the finalization of the AMI integration, the MDMS and data acquisition front end are fully operational. The AMI meets the Distributor’s expectations.
The installed new generation meters are covered by the MOC and the billing is based on remotely transmitted actual consumption data[17].
The deployed technology infrastructure has proven very effective and very stable, beyond even the expectations of the Distributor’s specialists involved in the project.

As for the meter replacement plan, the AMI network topology for the territory targeted by phase 1 is complete and the installation of routers and collectors, now 75% complete, is progressing as expected. By October 25, 2013, the Distributor had gone ahead with the installation of nearly 45% of the meters for phase 1. On December 31, 2013, more than 1 million new generation meters should be installed and read by the MOC.

Per the Measurement Canada S-E-02 and S-S-04 standards[18], the meter quality inspections are done continuously on each lot delivered. The meters meet the quality requirements called for in the contract.

[16] D-2012-127 (R-3770-2011), paragraph 219.
[17] D-2012-127 (R-3770-2011), paragraph 26.
[18] See Attachment B for the main technical standards applicable to the project.

BOX 2: AMI NETWORK PERFORMANCE

The deployed technology infrastructure has proven very effective and very stable, beyond even the expectations of the Distributor's specialists involved in the project.

- The daily meter reading results have reached 99.4%.
- In 99.9% of the cases the clients are invoiced based on a real reading.

The main reasons why a bill cannot be established from an actual reading of the client are because the new generation meter is no longer powered by the network. This situation can occur, for example, following work at the client, an emergency cut-off or destruction of the meter (by accident or fire).

The installation tempo exceeds the initially planned rate with an average volume for the month of September of more than 6000 meters installed per day with peaks of up to 8000 meters at the beginning of October. The Distributor noted that the installers' learning curve is stabilizing. The installation rate per day is different between the service provider and the Distributor's installers. This difference is solely attributable to the complexity of the installations done by each of the two groups; the internal installers perform all the complex installations. Thus, the average productivity rate of the service provider's installers is nearly 40 meters installed per day, whereas the rate for the Distributor's installers is 30 meters installed per day. These rates are greater than those planned for in the economic feasibility study underlying the LAD project. Additionally the Distributor's experience in phase 1 demonstrates that it takes a few months following hiring for an installer to be able to reach these standards.

B

OX 3: RESOURCES COMMITTED IN PHASE 1 DEPLOYMENT

The Distributor, its internal partners and the service provider have mobilized several resources in the LAD project phase 1 deployment, in particular:

- A field team totaling nearly 225 meter installers;
- Nearly 45 resources involved, in their respective domains, in the telecommunication infrastructure implementation;
- A Capgemini Québec call center composed of 20 agents;
- A fleet of about 200 vehicles.

Other resources are involved in various processes related to planning, sequencing activities, quality assurance, operational support, computer infrastructure maintenance, project management, communications and other project related activities.

3.2. Work for Phases 2 and 3

The work for phases 2 and 3 consists principally in installing the telecommunications infrastructure, and installation of new generation meters throughout the territory served by the Distributor, except for zones covered by phase 1.

In conformance with the approach selected in phase 1, the replacement of meters is done per zone in an accelerated manner. Actually, to make it possible to benefit from an AMI network, a critical mass of meters and related telecommunication equipment (routers and collectors) must be set up in order to provide for the meshing of the equipment comprising the system. Replacing all of the meters for a business office provides for eliminating manual reading and for immediately benefiting from efficiency savings. Additionally, in its decision D-2012-127, the Authority also emphasized that the spread over time of the deployment project would in particular have an impact changing the network configuration and the efficiency savings[19].

[19] D-2012-127 (R-3770-2011), paragraph 378.

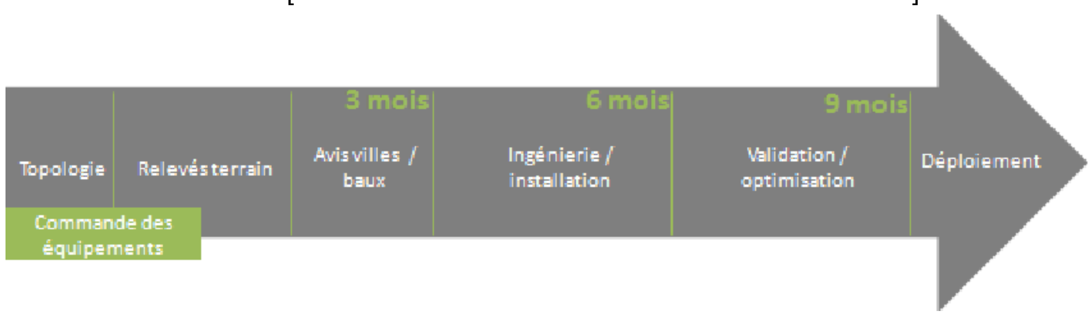
Set up Telecommunication Infrastructure

The work for setting up the telecommunication infrastructure will need to start 6 to 9 months before the beginning of the first new generation meter installations. Actually, the telecommunication infrastructure makes it possible for the mesh network to form and then the meters are read by the acquisition front end upon their installation. The telecommunication infrastructure represents an essential element of the AMI by enabling the meters to update their operating system and providing compliance with the high security level expected and required by the Distributor. Actually, following their installation, the meters supplement their advanced security by communicating with the telecommunication network.

Figure 1 illustrates the steps for installing routers and collectors prior to the installation of the meters.

FIGURE 1: STEPS PRIOR TO METER INSTALLATION

[three months six months nine months]



[Topology / Field Reports / Notices to Citie-Leases (3 months) /Engineering/Installation (6 months) / Validation/Optimization (9 months) /Deployment]
[Equipment order]

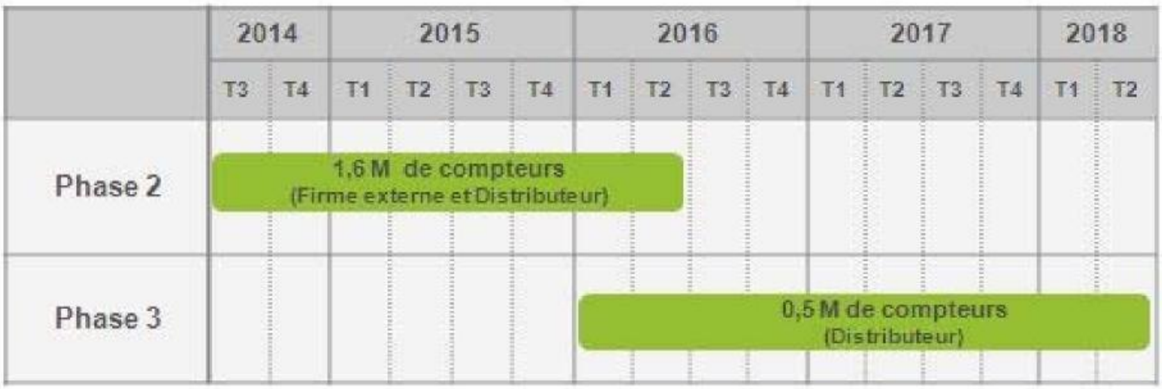
The Distributor first conducts the topology and field reports. It then sends notices and negotiates leases when necessary followed by the engineering. In the same way as phase 1, the installation of routers will be done by the Distributor's staff, whereas installation of collectors will be done by employees of the group – Hydro-Québec Technology. However, in addition to the time assigned for these activities, the Distributor must provide additional time in order to be able to revise its initial assumptions following the discovery of unexpected conditions, like, for example, when the selected location turns out to be unavailable because it is already reserved for incompatible purposes. Following the installation of telecommunication equipment, the Distributor goes ahead with an essential trial period during which it conducts tests in order to confirm the network's performance and optimization. It is only after these steps are past that it is possible to install meters.

Installation of the New Generation Meters

At the latest the Distributor plans to begin installing meters in July 2014, and at the earliest immediately following project authorization by the Authority. Meter deployment will finish by the end of the second quarter of 2018. In Figure 2 the Distributor shows the deployment schedule.

FIGURE 2: NEW GENERATION METER INSTALLATION SCHEDULE

[T1 = Q1; T2 = Q2; etc.]



[1.6 million meters (external firm and Distributor)]

[0.5 million meters (Distributor)]

For meter installation, the Distributor will make use of the services of an outside installer; this will make it possible to support a high installation tempo without jeopardizing current operations. The role of the service provider is to perform the simplest installations from phase 2. Thus, the very large majority of residential client meters are installed by employees of Capgemini Québec. Other meters (including those for business and industrial clients) from phase 2 and those from phase 3 are installed by the Distributor’s employees. There are no differences between this meter installation strategy and what was envisaged during the LAD project analysis in case R-3770-2011. It should be noted that the Distributor requires qualifications and a safety level conforming to its rules from the service provider.

In order to maximize the efficiency savings, the Distributor prefers an operation sequence with which to conduct a maximum of meter installations in a geographic zone in a short period while minimizing the number of passes in the zone. The Distributor’s approach is that shown in case R-3770-2011 and implemented in phase 1. The business offices for which there is a new generation meter deployment plan for phases 2 and 3 are shown in Table 1.

TABLE 1: BUSINESS OFFICES FOR PHASES 2 AND 3

Phase 2		Phase 3	
Châteauguay	Lévis	Baie-Comeau	Baie-James
Vaudreuil	Thetford-Mines	Sept-Îles	Rimouski
Drummondville	Beauce	Sherbrooke	Gaspé
Sorel	Hull	Boréal	Bonaventure
Valleyfield	Mont-Laurier	Shawville	Îles-de-la-Madeleine
Saint-Jean-sur-Richelieu	Trois-Rivières	Papineauville	Alma
Granby	Shawinigan	Maniwaki	Chibougamau
Saint-Hyacinthe	Victoriaville	La Tuque	
Beauport	Chicoutimi	Rouyn	
Québec		Val d'Or	

Note: The business offices are not listed in deployment order.

The deployment of meters will be done sequentially by phase, the decreasing end of installations for phase 2 overlapping the beginning of increasing installations for phase 3, in order to maintain the installation rate. The Distributor prefers to first deploy in the most densely populated zones of phase 2, which will make it possibly to rapidly generate efficiency savings. However, from considerations of efficiency, flexibility and logistics, the Distributor now intends to deploy simultaneously zones from phases 2 and 3 when it judges that the conditions require it: availability of labor in one region rather than another, location of warehouses and sites supporting deployment of adjacent zones and other operational considerations.

Table 2 shows the number of meters which will be replaced by phase, year and quarter. On the whole, the breakdown shown respects that filed during the LAD project analysis in case R-3770-2011.

TABLE 2: NUMBER OF EXISTING METERS REPLACED BY PHASE, YEAR AND QUARTER (IN THOUSANDS)

Number by Phase		Number by Year		Number by Quarter	
2	1.6 M	**2014**	542	**Q3**	271
				Q4	271
		2015	1,002	**Q1**	259
				Q2	287
				Q3	304
				Q4	152
Overlap of installations				**Q1**	109
				Q2	62
3	0.5 M	**2016**	275	**Q3**	52
				Q4	52
		2017	204	**Q1**	52
				Q2	51
				Q3	52
				Q4	49
		2018	83	**Q1**	48
				Q2	35

Project Management

In the same way as phase 1, the Distributor acts as principal contractor and lead integrator of the project[20]. In this way, a dedicated team, the project office, will continue to provide LAD project management and drive the meter replacement plan. The project office closely tracks the project costs and looks to make permanent and to track the efficiency improvements generated by the LAD project[21].

3.3. Critical Dates for the Phase 2 Work

As previously indicated, following project authorization by the Authority, the Distributor will begin installation of the meters for phase 2 early in July 2014 at the latest. To avoid a break in the meter installation tempo between phase 1 and phase 2, the installation in advance of routers and collectors for phase 2 is an essential condition; just as it was in phase 1. Hence, in order to be in a position to start installation of phase 2 meters at the beginning of the

[20] D-2012-127 (R-3770-2011), paragraph 36.
[21] D-2012-127 (R-3770-2011), paragraphs 351, 364 and 531.

third quarter of 2014, the installation of telecommunication equipment will need to start at the beginning of 2014 at the latest.

A delay in starting installation of phase 2 meters could have significant consequences on the project costs and deployment schedule. Actually, in case of delaying the start of phase 2, the Distributor, its internal partners and the service provider will need to let a significant number of experienced employees go, without assurance of their availability when the deployment activities resume. When restarting installations, it is likely that new employees will need to be hired and trained.

Alternatively, keeping teams in place, without however being able to keep them fully occupied, could lead to additional costs, especially among the permanent employees of the Distributor and its internal partners.

A delay in the deployment of phase 2 could lead to the following impacts:

- An increase of the expected costs related to hiring and training employees;
- Additional costs to be incurred related to maintenance activities, especially involving warehouse logistics, renting vehicles and renegotiating existing contracts;
- Delays in the planned schedule related to hiring and training activities, even a temporary reduction of the installation rate related to the learning curve for new installers.

These impacts will have an effect on the realization of the expected efficiency savings.

Additionally, the Distributor observes that the favorable reception by the clients, expected costs for phase 1 below planned levels and the meter installation tempo observed over the weeks – much higher than expected – are items which argue for continuing the deployment in phases 2 and 3. Additionally the Authority can assess the progress of the work completed and to come for phase 1 from the results presented in the quarterly tracking September 30, 2013. With these probative results, a complete case can be filed with the Authority.

For these reasons, the Distributor respectfully asked the Authority to issue a priority decision authorizing starting work, in December 2013, for installing telecommunication equipment in the Châteauguay, Granby, Saint-Hyacinthe, Saint-Jean-sur-Richelieu, Sorel, Valleyfield and Vaudreuil regions and also on Hydro-Québec installations such as poles, buildings and land belonging to Hydro-Québec. The choice of business offices is dictated by the fact that they involve densely populated regions. That way, while the experienced teams start installing meters in some of these regions, the service provider will go ahead with hiring and training local installers for the other phase 2 regions. The installation of equipment on Hydro-Québec installations is easy and makes it possible to quickly open new zones for deployment. By performing these installations at the beginning of phase 2 and 3 deployment, the Distributor first increases its operational flexibility and can next concentrate its efforts on installing telecommunications equipment for other regions not targeted by the priority decision.

The costs for installing the telecommunication equipment are estimated at about $6.4 million for the first six months of 2014. The Distributor indicates that these costs are already planned in the telecommunication equipment costs for investment (see Section 5.1).

4. REGULATORY APPROACH

In connection with the case R-3770-2011, the Distributor chose to present the LAD project in three distinct phases, with each of the phases being the subject of a specific authorization request under Article 73 of the Law. The selection of the phases is justified by the size and length of the LAD project. In its decision D-2012-127, "the Authority considers that this approach is adequate and prudent."[22]

However, beyond the installation of the AMI in phase 1, few things distinguish one phase from another as it concerns the replacement of the meters, other than the volumes of meters to be installed and the density of the clients in the targeted areas

First, the Distributor observes that a significant portion of the costs planned in phases 2 and 3 is set by contract (see Section 5.1.3). Additionally, the early costs for phase 1 at this date and the observed meter installation tempo are such that the Distributor is confident that the assumptions concerning equipment installation and

[22] D-2012-127 (R-3770-2011), paragraph 523.

meter replacement, which had been established based on its experience, will be realized in phases 2 and 3 (see Section 5.1).

Furthermore, the technology infrastructure deployed in phase 1 of the project has proven very effective and very stable, beyond even the expectations of the Distributor's specialists involved in the project. Thus, the Distributor also expects a high performance level from the technology infrastructure for phases 2 and 3, even if the client density is lower in the targeted territories.

The Distributor indicates that when filing the phase 1 authorization request, using satellite links for establishing communication with new generation meters where cell coverage was not available was considered.

Considering the increases in cellular coverage over recent years, the Distributor decided to use cellular links for a large majority of the collectors in the territories covered by phases 2 and 3. Because of this better cellular coverage, the Distributor is of the opinion that the continuation of the telecommunications deployment with the technology used in phase 1 remains the most economically viable in the short and medium term.

Additionally, the work done up to now in phase 1 shows that the technology infrastructure in the less densely populated areas or borderline areas would have greater performance if the deployment was not limited to the phase 2 territory, but included contiguous areas from phase 3. For reasons of efficiency and logistics, the Distributor now intends to simultaneously deploy phases 2 and 3, when it judges that the conditions require it (see Section 3.2).

Considering all of the previous considerations, the Distributor thinks it is opportune to present a single authorization request for LAD project phases 2 and 3.

5. PROJECT ASSOCIATED COSTS

In the case R-3770-2011, the LAD project total cost was established at $997.4 million. This amount included $839.9 million of investments and $157.4 million of operating charges during the project[23]. The Distributor incorporated a contingency on the LAD project cost elements which could vary and which was $21.3 million for the investments and $8.1 million for the operating charges[24]. The Distributor indicates that the LAD project headings and cost details were the subject of an in-depth analysis by the Authority and the participants during the study of the phase 1 authorization request.

In paragraph 331 of its decision D-2012-127[25], the Authority noted that: "…even if the [LAD] Project is not risk-free, the evidence submitted to the Authority tends to indicate that the Project budget is comparable to what was done elsewhere and even higher…."

In its decision D-2012-127, the Authority authorized the execution of phase 1 for a total cost of $440.5 million[26].

5.1. Costs of Phases 2 and 3

The cost for phases 2 and 3 of the LAD project, presented in Table 3, totals $557.6 million.

The share for the investments is $435.9 million to which operating charges during the project of order $118.1 million are added. For phases 2 and 3, the Distributor planned for a contingency of $13.3 million on the investments and $5.9 million on the operating charges. The costs anticipated for phases 2 and 3 are in line with those filed in connection with case R-3770-2011, but offset in time to take into account the delay of starting deployment, initially planned for June 2012.

The experience acquired during phase 1 serves to confirm that the cost assumptions filed in connection with case R-3770-2011 are valid for phases 2 and 3.

Actually, the assumptions initially made took into account specific items from phases 2 and 3. There is therefore no reason to revise them.

[23] D-2012-127 (R-3770-2011), paragraph 51.
[24] D-2012-127 (R-3770-2011), paragraphs 53 and 335.
[25] See also paragraph 330.
[26] D-2012-127 (R-3770-2011), page 121.

TABLE 3: COSTS FOR LAD PROJECT PHASES 2 AND 3 (2014-2018) (IN M$)

	2014	2015	2016	2017	2018	Total
Investments	**110.5**	**159.3**	**74.4**	**65.4**	**29.9**	**439.5**
Purchasing and installing meters	96.9	132.5	51.6	39.2	22.1	342.3
Telecommunications equipment	6.4	20.8	18.9	20.1	7.2	73.4
Project office	5.7	5.4	3.7	6.0	0.6	21.4
Capitalized borrowing costs	1.4	0.6	0.2	0.2		2.4
Operating charges	**12.3**	**33.8**	**37.6**	**23.8**	**10.6**	**118.1**
Relocalization of resources	0.4	8.6	11.2	3.4	0.2	23.9
Information Technologies	5.4	11.4	12.3	10.7	5.7	45.6
Telecommunications	1.7	4.6	5.4	4.3	2.1	18.2
Various charges	4.8	9.2	8.6	5.3	2.6	30.5
Total	**122.8**	**193.1**	**112.0**	**89.2**	**40.6**	**557.6**

Note: Deployment ends at the end of the second quarter of 2018.

5.1.1. Investments

The purchase and installation cost for the meters totals $342.3 million. The price for the meters and the cost of the installations done by the service provider – Capgemini Québec – come from the request for proposals done in connection with the preparatory work[27]. The two suppliers of meters are Landis+Gyr (for a maximum of 80% of the meters) and Elster (for a minimum of 20% of the meters).

The project office will acquire the new generation meters based on the expected deployment tempo. The cost of installations performed by the Distributor's personnel follows the service costs. The installation cost is also made up of quality insurance expenses and work done by master electricians[28]. The phase 1 results confirm the fitness of the assumptions concerning the cost of installations done by the Distributor's employees. Consequently, the Distributor does not foresee any risk in this respect.

[27] D-2012-127 (R-3770-2011), paragraph 219.
[28] These items were under the heading "Other Investments" in the case R-3770-2011.

The purchase and installation cost of the telecommunication equipment (collectors and routers) is $73.4 million. The purchase price is the result of a request for proposals done in connection with the preparatory work[29]. The project office will acquire that from the Landis+Gyr supplier based on the expected deployment tempo. The installation cost of the telecommunications equipment is an estimate which takes into account difficulties inherent in the activities in the regions (e.g. travel distance, site topologies) and the assumptions on which the estimate is based are confirmed by experience acquired in phase 1.

The $21.4 million in project office costs include the costs related to project governance, deployment operations and technology monitoring. The project office activities are not different from those which were assigned to it in connection with phase 1.

The $2.4 million in borrowing costs to be capitalized were calculated using the Distributor's tariff base yield rate, as authorized by the Authority in its decision D-2004-47. They were calculated with a yield rate of 7.264% authorized by the Authority in its decision D-2011-028 The Distributor did not actualize the borrowing cost to be capitalized at the 6.380% rate authorized by the Authority in its decision D-2013-037, considering the small impact on the costs.

For the investments, the contingency is incorporated in each of the cost headings.

5.1.2. Operating Charges during the Project

The operating charges include the costs for relocating employees assigned to the actual processes for reading and collection (service cut-off and restoration) for an amount of $23.9 million.

in connection with phase 1, the relocalization efforts made by the Distributor had a result that some permanent readers were reassigned into the areas not yet targeted by the deployment. These permanent employees could possibly need to be placed in other employment within the company again.

[29] D-2012-127 (R-3770-2011), paragraph 219.

The Distributor indicates that the relocalization costs take into account the degree of difficulty of replacement related to the pool of available positions and the work location. In the case R-3770-2011, the Distributor made the assumption that the average relocation period for an employee in urban region would be at most six months, and that this period would be at most 12 months for an employee in semi-urban region and at most 24 months for an employee in rural region. These assumptions are retained in the present case. Since the positions for temporary employees were abolished, there is no relocalization cost.

The $45.6 million in IT costs include costs for licenses, their maintenance and their operation.

For telecommunication there are costs of $18.2 million for maintenance and operation of the routers and collectors, and also for telecommunication services provided by Rogers Communications Inc.

The $30.5 million in various charges is principally made up of costs related to training, communication, information campaigns, client activity (during the installation period for the meters) and contingency. Under the heading of communication activities, the larger number of towns and the more vast area of the territories to be traversed in phases 2 and 31 doubted le lead to costs consistent with those planned in case R-3770-2011, and therefore higher than the costs observed in phase 1.

5.1.3. Contingency

For the cost components not guaranteed by contract and which could therefore vary, the Distributor incorporated a contingency. Therefore, for the investments, no contingency was planned in connection with the meters, telecommunication equipment and the portion of the installations that will be done by the service provider at a fixed cost per meter.

The Distributor judges it prudent to retain the assumptions concerning the contingency amounts evaluated for the LAD project. Thus, for phases 2 and 3, a contingency of $13.3 million is planned for the investments on the basis of a 12% rate applied to the installation cost of the meters done internally, the quality assurance expenses, the cost of work done by master electricians and the installation cost of the telecommunication equipment[30]. This rate was established on the basis of the risks estimated for each of these internal cost components and considering the Distributor's experience in meter installation.

Similarly a contingency of $5.9 million is planned on the operating costs. This is calculated on the basis of a 12% rate applied to all of the operating charges except for IT and telecommunication.

In paragraph 363 of its decision D-2012-127, the Authority showed it was satisfied with the Distributor's evidence. The Authority noted that some facts provide a reasonable guarantee that the LAD project will be done within the costs presented, in particular[31]:

- The new generation meters are provided at prices set by contract.
- The routers and collectors are purchased at prices set by contract.
- Telecommunication services are provided by a major company under conditions established by contract.
- The subcontracting of a significant portion of the meter installation operations is at fixed cost and subject to performance indicators.
- Contingencies are planned for costs not guaranteed by contract

As for certain costs not guaranteed by contracts, the fitness of several assumptions became more definite during the execution of phase 1, in particular relating to the cost of installations done by the Distributor's staff. Consequently, the Distributor is even more confident that LAD project phases 2 and 3 can be completed within the planned costs. Considering only the meter replacement plan, the principal differences between phase 1 and phases 2 and 3 involving costs are the surface area of the territory to be crossed and the larger numbers towns involved. These items had been considered in establishing the cost assumptions. Thus, even though on September 30, 2013 it anticipates a favorable variation from the planned phase 1 costs, the Distributor thinks that the factors which made it possible to generate this favorable variation might not be realized in phases 2 and 3. Consequently, out of concern for prudence, the Distributor is not modifying its cost assumptions and not reducing the contingency amounts for phases 2 and 3.

[30] D-2012-127 (R-3770-2011), paragraphs 53 and 335 to 337.
[31] D-2012-127 (R-3770-2011), paragraphs 329, 333, 363 and 528.

Table 4 shows the annual contingency amounts.

TABLE 4: PLANNED CONTINGENCY PER YEAR
(IN M$)

	2014	2015	2016	2017	2018	2019	Total
Investments	1.7	3.6	3.7	3.0	1.3	-	**13.3**
Operating charges	1.9	2.1	0.7	0.2	0.7	0.4	**5.9**
Total	**3.6**	**5.7**	**4.3**	**3.2**	**2.0**	**0.4**	**19.2**

Note: Deployment ends at the end of the second quarter of 2018. Contingency for 2019 is related to relocation costs. In Table 3, contingency for 2019 is included in the costs for 2018.

6. MAIN RISKS ASSOCIATED WITH THE PROJECT

The mitigation measures principally aim to assure a reduction of the risks linked in particular to the operational aspects of the deployment such as the installation tempo and the deployment strategy. In connection with the phase 1 request, the Distributor identified the following risks:

- Cost overruns
- Clientele acceptability of meter replacement
- IT failure
- IT and telecommunication security
- Human resources
- LAD Project Governance

In light of the experience acquired in phase 1, the Distributor does not foresee additional risks for LAD project phases 2 and 3. The Distributor is keeping close track of the main risks even though the probability of them occurring is now considered to be low.

6.1. Cost Overruns

Although there are still risks relating to cost overruns[32], the Distributor thinks that the probability of their occurrence is low.

As previously indicated, the Authority stated that it was satisfied with the Distributor's evidence which it summarized in paragraph 333 of this decision D-2012-127[33]:

> The evidence indicates that the purchase [sic] and installation costs of the [new generation meters] (NGM) are guaranteed by contract and subject to performance indicators [footnote omitted]. The evidence also indicates that the routers, collectors, MDMS and acquisition front end are also the subject of negotiated firm prices that are guaranteed by contracts [footnote omitted].

The costs for phase 2 and 3 work are in large part made up by the purchase and installation of devices and equipment at fixed cost. However, the phase 3 meters will be installed solely by the Distributor's staff.

The risk of cost overruns for phases 2 and 3 is mainly related to the expanse of the territory, but this is limited by the fact that the embedded technology is proving effective and stable for phase 1. The Distributor thinks that it will be the same for phases 2 and 3.

The Distributor's experience with phase 1 demonstrates the fitness of the initial assumptions. Additionally, the Distributor has established a project office for close tracking in order to produce compliance with planned costs and will maintain this tracking throughout phases 2 and 3.

Additionally, the Distributor emphasizes that the total cost of the LAD project must not exceed the amount authorized by the Hydro-Québec Board of Directors by more than 15%, otherwise it must obtain a new authorization from the board. Should a possible but unlikely LAD project cost overrun occur, the Distributor shall inform the Authority of it in due time.

[32] D-2012-127 (R-3770-2011), paragraph 529.
[33] See also paragraphs 52, 332 to 338 and 361 of decision D-2012-127.

6.2. Clientele Acceptability of Meter Replacement

The majority of clients receive the project favorably. This observation is confirmed by installers in the field. Items such as good progress of installations in the field and the low rate of subscribing to the opt-out option support[34] the observation. Additionally, the Distributor receives few calls or inquiries from clients concerning the project. It makes every effort to reply on an individual basis and does not hesitate to review the need for communication tools[35].

The clients' favorable perception is also reflected in the meter installation client satisfaction polls. The rates of complaints received by the Distributor and service provider have proven to be very low[36].

Based on all these factors it can be concluded that the probability of this risk occurring is low.

BOX 4: CLIENTELE ACCEPTABILITY OF METER REPLACEMENT

The majority of clients receive the LAD project favorably.

- 634,000 new generation meters installed and read by the MOC;
- under 2000 non-communicating meters installed, which is an opt-out option subscription rate of 0.3% – well below the 1% rate expected in connection with case R-3770-2011;
- small number of inquiries (telephone calls and emails) from clients concerning the LAD project;
- fewer than 200 complaints received by the Distributor and service provider, which is 0.03% of the meters installed;
- new generation meter installation satisfaction rate of 8.8 out of 10 for the Distributor's installers and 8.6 out of 10 for the installations done by the service provider's installers.

Note: Data from September 30, 2013.

[34] D-2012-128 (R-3788-2012).
[35] D-2012-127 (R-3770-2011), paragraph 485.
[36] See la section 6 de la pièce HQD-1, document 2.

Additionally, the Authority accepted that the scope of the LAD project be limited to only remote meter reading and service cut-off and restoration automation functionalities[37], in order to enhance social acceptability. It should be observed that the Distributor strategy, governed by the real-world experience of hundreds of electricity distribution companies[38], was adequate.

6.3. IT Failure

The Distributor's real-world experiences at the time of filing the present request serves to confirm that the probability of occurrence of IT failure risk is low because the solution is now installed and stable. Technology infrastructure management is integrated with IT governance in Hydro-Québec and conforms to various company oversights. Beyond the IT governance, the project office chose to maintain a rigorous tracking of this risk item.

6.4. IT and Telecommunication Security

As it involves IT and telecommunication security, the Distributor is maintaining its preventive measures that include data encryption, access control, command signatures, event logging, network monitoring, redundancy and conducting intrusion tests. A continuous look-out is maintained to adapt the security measures to the strictest standards. The Authority has declared itself "satisfied with the security measures… taken by the Distributor in order that data recorded by the [New Generation Meters] (MGM) and transmitted by the AMI not be intercepted by third parties."[39] In this category, the project office is also maintaining a rigorous tracking of the actions taken, even if the solution security is integrated to the company's IT governance.

Additionally, the Authority also notes in its decision D-2012-127, that "… the evidence shows the Distributor keeps a continuous lookout on the development of information technologies and that it is active in international bodies working on the subject…"[40].

[37] D-2012-127 (R-3770-201 1), paragraphs 17 and 484 to 493.
[38] D-2012-127 (R-3770-201 1), paragraphs 18 and 22.
[39] D-2012-127 (R-3770-201 1), paragraph 516. See also paragraphs 29, 33 and 512 to 517 on the measures taken by the Distributor on the subject of cyber security.
[40] D-2012-127 (R-3770-2011), paragraph 518.

6.5. Human resources

Concerning human resources, the Authority noted in its decision D-2012-127 that “the evidence shows that the Distributor currently has a window of opportunity for reorganizing its operations without creating significant negative impacts for its employees.”[41] The risk identified involving relocalization of resources is minimized by the active involvement of the individual unions. Executive management of the company took over the case and the relocalization plan for the resources goes beyond compliance with the collective agreements because the unions are collaborating in the management of the project’s issues. The status tracking mechanism for the staff and relocation pool established in connection with phase 1 of the LAD project is maintained.

6.6. LAD Project Governance

The execution of phase 1 of the project supports concluding that the governance set up assures coverage of all the issues presented. The project continues to be closely tracked and the necessary measures are in place for assuring that it meets its objectives and planned costs. The selected approach of dividing the whole project into distinct phases for deployment purposes remains the same: phase 1 and phases 2 and 3 combined for reasons of efficiency.

[41] D-2012-127 (R-3770-2011), paragraph 230. See also paragraphs 231 and 232.

7. ECONOMIC FEASIBILITY STUDY

In the case R-3770-2011, the economic analysis presented in support of the evidence covered the LAD project as a whole[42]. In its analysis, the Distributor compared the AMI scenario (LAD project scenario) to a reference scenario in which it continued progressive replacement of the embedded base of in-service meters by electronic meters over a period of 20 years[43]. As it concerns this economic analysis, the Authority concluded in decision D-2012-127, that it should "reflect all of the project costs, including the IT costs which are intrinsic to the [LAD] Project."[44]The savings generated by the AMI scenario compared to the reference scenario are consequently estimated at $201.9 million (actualized to 2011) over 20 years.[45]

Following questions from the Authority and participants concerning the assumptions on which the scenarios rested, the Distributor also confirmed the favorable conclusions of the LAD project economic analysis, in particular by doing two hypothetical scenarios[46]:

- Replacement of the new generation meters and telecommunication equipment from the AMI scenario after 15 years;
- The uniform annual replacement of in-service meters by electronic meters from the reference scenario.

In the same way as the economic analysis, the hypothetical scenarios serve to demonstrate that the AMI scenario remains very advantageous compared to the reference scenario.

In its decision D-2012-127, the Authority indicates in paragraph 314 that "considering the actual state of knowledge, the Authority is satisfied by the evidence from the Distributor and the conclusion from its economic analyses."[47]

[42] D-2012-127 (R-3770-2011), paragraph 522.
[43] D-2012-127 (R-3770-2011), paragraphs 54 and 241. Additionally, the AMI and reference scenarios are described in paragraphs 55 to 56 and 242 to 254.
[44] D-2012-127 (R-3770-2011), paragraph 310.
[45] D-2012-127 (R-3770-2011), paragraphs 257 and 311.
[46] D-2012-127 (R-3770-2011), paragraphs 63 and 256. Hypothetical scenarios are described in paragraphs 260 to 265. The Distributor also produced a sensitivity analysis on the analysis period (15 years instead of 20 years).
[47] In paragraphs 312 to 324 of the decision D-2012-127, the Authority issued a favorable opinion on several specific aspects of the Distributor's economic analysis.

In paragraph 525[48], the Authority concludes by indicating the following:

> The Authority authorizes the Project, because the results of four economic analyses, including the feasibility studies, serve to confirm the robustness of the AMI scenario compared to the reference scenario. In this respect, the participants proposed many modifications to the assumptions and calculation methods of both scenarios – in particular these had the consequence of increasing the AMI scenario costs and reducing the cost of the reference scenario. However, there was no result that allowed the Authority to conclude the AMI scenario is not the most profitable project. [Distributor added underlining.]

Because it covered the entire LAD project, the conclusions the economic analysis presented in support of the phase 1 authorization request still remain valid.

7.1. Expected Efficiency Savings

The essential part of the benefits expected from the LAD project[49], and included in the economic analysis, rest on efficiency savings in the activities related to meter reading, client service cut-offs and restoration, and bringing the meters into compliance[50]. These savings result principally from a reduction of the salary base[51].

The LAD project's impact on human resources is seen as an elimination of 726 positions from now to the end of deployment of the entire project[52]. The Distributor confirms that it remains confident of being able to achieve these savings by continuing phases 2 and 3 of the LAD project, because they come from the withdrawal of specific activities and processes, and their evaluation rests on these facts[53]. The project office, established for the whole LAD project, has the responsibility of seeing that these efficiency savings are made real and monitored[54].

[48] See also paragraph 324.
[49] Several paragraphs from the decision D-2012-127 (R-3770-2011) deal with efficiency savings, in particular: paragraphs 19, 24, 44 to 47, 227 to 232, 348 to 351, 367 and 369.
[50] D-2012-127 (R-3770-2011), paragraph 350.
[51] D-2012-127 (R-3770-2011), paragraph 227.
[52] D-2012-127 (R-3770-2011), paragraph 227.
[53] D-2012-127 (R-3770-2011), paragraph 351.
[54] D-2012-127 (R-3770-2011), paragraph 364.

7.2. Other Solutions Considered

The Distributor is not presenting other solutions in connection with the present request.

As emphasized by the Authority in paragraph 526 of the decision D-2012-127:

> As for the other solutions considered [footnote omitted] by the Distributor for the LAD Project, it needs to be recalled that the Distributor went ahead with requests for proposals in order to obtain open proposals for all available communication technologies. Hence, the proposals received, which responded to the objectives assuring the durability of the embedded base of meters, achieve efficiency savings and make the offering of new services to the clients possible, based on establishing a wireless technology and the acquisition of [new generation meters] (NGM).

The Distributor therefore plans to continue deployment of the technology selected for LAD project phase 1. At the time of making its technology choice, the Distributor was confident of having chosen a mature technology and one which constituted the direction of the market[55]. The Distributor's current observations further confirm that the selected technology still constitutes the standard in the industry today and is widely deployed elsewhere in the world

7.3. Sensitivity Analysis

The Distributor did two sensitivity analyses, which were presented in connection with the case R-3770-2011[56]:

- Increasing the employee relocalization costs;
- Increasing the investment costs.

In the first analysis, the Distributor made the assumption that the relocalization of the employees would be more difficult than expected and would require payment of two-year salary per affected employee. The relocalization costs would then increase by $25 million (actualized). The Authority concluded that "[t]his analyses shows that the Distributor still has a significant operating margin for completing the [LAD] Project."[57]

In the second analysis, the Distributor varies the investment costs until they cancel the reduction of discounted costs between the reference scenario and the AMI scenario. The Authority concluded that "since 82% of the [LAD] Project costs are fixed by contract, the results of this sensitivity analysis showed that the Project's variable costs

[55] D-2012-127 (R-3770-2011), paragraphs 27, 28 and 203.
[56] D-2012-127 (R-3770-2011), paragraphs 59 to 61 and 325.
[57] D-2012-127 (R-3770-2011), paragraph 325.

[not set by contract] would need to be increased 54% for the cost of the two contracts to match."[58]

Furthermore, the economic analysis over 15 years instead of over 20 years, which limits the savings coming from the deployment of the AMI scenario, again confirms the conclusions concerning the LAD project[59].

8. IMPACTS ON THE DISTRIBUTOR'S REQUIRED REVENUE

In the case R-3770-2011[60], the Distributor presented an analysis of the LAD project's impact on its required revenues over a 20 year period starting from the beginning of phase 1. The impact is measured by the difference between the required revenues necessary under the reference scenario and those necessary under the AMI scenario, to which is added charges for accelerated depreciation and write-off of 3.8 million in-service meters which are replaced during the LAD project. In this respect, the Authority confirms, in paragraph 379 of its decision D-2012-127, the accelerated depreciation and write-off are part of the costs arising from the LAD project beginning from the moment when this project is authorized. The maximum tariff impact on the required revenues is felt during phase 1 of the LAD project[61]. The results of the financial analysis presented in case R-3770-2011 still remain valid.

In paragraph 373 of decision DE-2012-127, the Authority noted that "[t]he [LAD] Project should exert a downward pressure on tariffs starting in 2018, because of the expected efficiency savings coming from automation of consumption reading and from remote service cut-off and restoration." The Distributor indicates that starting in 2019 it anticipates recurring savings evaluated at $81 million per year[62]. This conclusion remains valid, considering that, because of expected efficiency savings, the project will add at its end exert a downward pressure on the tariffs[63].

[58] D-2012-127 (R-3770-2011), paragraph 325.
[59] D-2012-127 (R-3770-2011), paragraphs 62 and 324. The analysis is given in paragraphs 258 and 259.
[60] D-2012-127 (R-3770-2011), paragraphs 64 and 370 to 379.
[61] D-2012-127 (R-3770-2011), paragraph 372.
[62] D-2012-127 (R-3770-2011), paragraphs 44 and 349. The interval, 2018 to 2019, for achieving recurring annual savings of $81 million principally follows from the delay of the bulk deployment and from the revision of the phase 1 deployment schedule.
[63] D-2012-127 (R-3770-2011), paragraph 523.

9. IMPACTS ON SERVICE QUALITY

In paragraphs 65 and 234 of its decision D-2012-127, the Authority noted that the LAD project offered concrete and immediate benefits to the clients; they are:

- Issuing bills based on their actual and not estimated consumption;
- No visit required to their home or business for meter reading purposes;
- Greater accuracy of the data which makes it possible to develop advantageous solutions for the client.

After deployment phase 2 and phase 3 clients will get these concrete benefits. Thus, in paragraph 235 of its decision D-2012-127, the Authority emphasizes that "[t]he advantage of billing based on actual reading of data recorded by the [new generation meters] (NGM) is not negligible", considering the number of complaints before the Authority from clients concerning electricity consumption and billing.

Under the heading of moving in and moving out, on September 30, 2013 the Distributor processed 51,000 remote meter readings on the move-out date indicated by the client without other involvement on their part.

For outage management, the Distributor has incorporated signals coming from new generation meters in its outage detection algorithm[64]. These signals are added to the information communicated by clients reporting an outage by telephone.

The LAD project will also make possible remote service cut-off and restoration and therefore greater service efficiency[65]. The process related to the service cut-off and restoration function will be implemented in the first quarter of 2014.

Parallel to the installation of the AMI technology and the installation of the meters, the Distributor worked on several projects related to embedded new technology which will result in new client services or an improvement of the distribution service quality (see Section 2).

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[64] The outage detection functionality, which is not included within the scope of the LAD project, is however not embedded.

[65] D-2012-127 (R-3770-2011), paragraphs 67 and 68.

BOX 5: NEW GENERATION METERS AND RADIO FREQUENCIES

The LAD project does not impact consumer health.

In this respect, the Authority indicated in paragraphs 387 and 480 of its decision D-2012-127 that "… the evidence clearly shows that there is no basis for concerns about health effects of installing [new generation meters] (NGM)" and that "[t]he opinion of public health authorities and the state of scientific research on the nonthermal impacts and effects of this type of [radiofrequency] (RF) on health clearly confirms that there is no health danger."

The Authority's opinion is based both on imposing technical evidence concerning the radiofrequency powers to which the public is exposed and the radiofrequency powers emitted particularly by the new generation meters and also the opinion of a physician, specialist on the health effects of radio frequencies. The Authority also considered the opinions of the Québec Ministry of Health and Social Services (MSSS), Health Canada and the World Health Organization (WHO) in this respect[66].

The overall analysis of the scientific understanding of the health effects of radio frequencies has not changed since the decision D-2012-127 rendered by the Authority in October 2012 concerning authorization of LAD project phase 1.

[66] D-2012-127 (R-3770-2011), paragraph 394. The opinion of the Authority on health impacts is presented in paragraphs 387 and 390 to 483. The Distributor's evidence is summarized in paragraphs 70 to 83.

10. AUTHORIZATIONS REQUIRED UNDER OTHER LAWS

In paragraph 519 of its decision D-2012-127, the Authority noted that:

> This regulatory requirement is satisfied. …, the LAD Project as such does not have to be authorized under other laws. The equipment compliance statements were filed with the present case. Except for [new generation meters] (NGM) which will be installed at clients, the Distributor mainly installs AMI equipment on its own installations (e.g. poles, etc.). Thus no special legal authorization is required for their installation.

Since decision D-2000 127, no legislative or regulatory provision has had the effect of subjecting the project to an authorization.

11. REGULATORY HANDLING

The costs inherent in the project (operating costs, other costs and yield from the rate base) and also the revenues from bringing into compliance – everything totaling $27.9 million[67] – have been included in the required revenues for the control year 2014 in connection with the rate case 2014-2015 (R-3854-2013). However, should it happen that the project not be authorized before the Authority's decision on the rate case expected at the beginning of March, the Distributor asks, in conformance with D-2012-024[68], that these costs be paid in an off tariff base set-aside account until a project authorization is issued; the disposition of this account will be handled subsequently in the required revenues for a subsequent tariff request.

[67] See Table 1 from document HQD-4, document 2 (B-0019) in the case R-3854-2013, *Application concerning the Establishment of Electricity Tariffs for Tariff Year 2014-2015*.
[68] D-2012-024 (R-3776-2011), paragraphs 128 and 129.

12. PROJECT TRACKING METHOD

Starting with the date of the Authority's decision concerning phases 2 and 3, the Distributor proposes presenting LAD project phases 1, 2 and 3 results tracking without distinguishing the phases. Actually, the Distributor is of the opinion that a breakdown by phase would not provide additional refinement pertinent to LAD project tracking. Tracking the tempo of the installation of meters and the alignment with the costs is sufficient for confirming the good progress of the project. The same applies to the breakdown of expected costs by quarter. Actually, the Distributor makes forecasts and sets its objectives on an annual basis for project management purposes. A breakdown of the expected costs by quarter will be presented for the current year.

Thus, the Distributor proposes that the following information be the subject of LAD project costs and schedule progress tracking:

- The number of planned and installed new generation meters by quarter;
- The number of non-communicating meters installed per quarter at clients making use of the opt-out option;
- The expected costs by year except for the aggregated remaining quarters of the year in progress;
- The actual cost by quarter;
- A status of the materialization of the efficiency savings stated in the case R-3770-2011;
- The number of client complaints received per quarter, organized by the type of reasons;

As necessary, the Distributor will provide explanations for the main cost and schedule deviations and, when the deviations are significant, will present new forecasts for the costs and number of new generation meters to be installed.

Additionally, the Distributor proposes to report on the schedule of embedding functionalities which are planned but not included in the scope of the LAD project in connection with the quarterly tracking when required.

The proposed tracking by the Distributor complies with the quarterly tracking already filed with the Authority for phase 1.

ATTACHMENT A: ALIGNMENT OF THE AUTHORIZATION REQUEST WITH REGULATION

ALIGNMENT OF THE AUTHORIZATION REQUEST WITH REGULATION

Regulation **Request**

Art.	Al.	Par.	Required Information	Section/D-2012-127
2	1	1°	The project's target objectives	Section 2 D-2012-127, par. 15, 220, 221, 238, 240 and 348
2	1	2°	The project's description	Sections 3.2 and 3.3
2	1	3°	The project's justification in relation with the target objectives	Section 2 D-2012-127, par. 16, 38 to 50, 205 to 213, 222 to 233, 237, 238, 240, 504 and 505
2	1	4°	The project's associated costs	Section 5.1 D-2012-127, par. 52, 53, 332, 333, 336 to 338, 363, 366 to 368 and 528
2	1	5°	The project's economic feasibility study	Section 7 D-2012-127, par. 54 to 63, 241 to 265, 286, 298 to 324, 325 to 331, 350, 367 and 521 to 525
2	1	6°	The list of authorizations required under other laws	Section 10 D-2012-127, par. 84 and 519
2	1	7°	The impact on the tariffs including a sensitivity analysis	Section 8 D-2012-127, par. 64, 370 to 379
2	1	8°	The impact on the grid's reliability and the quality of service	Section 9 D-2012-127, par. 65 to 69, 234, 235 and 511
2	1	9°	The other solutions considered, as applicable	Section 7.2 D-2012-127, par. 27, 28 and 526
3	1	1°	List of main technical standards	Attachment B
3	1	2°	The contractual commitments and their financial contributions, as applicable	N/A

ATTACHMENT B: MAIN TECHNICAL STANDARDS

List of Main Technical Standards Applicable to the LAD Project

Measurement Canada:

- S-S-04: Sampling Plans for the Inspection of Isolated Lots and Short Series of Lots
- S-E-02: Specifications for the Verification and the Reverification of Electricity Meters
- S-S-06: Sampling Plans for the Inspection of Isolated Lots of Meters in Service[69]
- LMB-EG-07: Specifications for Approval of Type of Electricity Meters, Instrument Transformers and Auxiliary Devices.
- GS-ENG-07-03: Administrative Process for the Certification of Measuring Apparatuses[70]
- ICES-003: Digital Apparatus

Other Regulatory Bodies:

- PS-EG-02: Provisional Specifications for the Means and Methods of Sealing Verified Electricity and Gas Meters
- ANSI-C-12.1: Code for Electricity Metering;
- ANSI-C-12.10: Physical Aspects of Watthour Meters;
- ANSI-C-12.18: Protocol Specification for ANSI Type 2 Optical Port;
- ANSI-C-12.19: Utility Industry End Device Data Tables;
- ANSI-C-12.20: 0.2 and 0.5 accuracy classes ;
- ANSI-C-12.22: Protocol specification for interfacing to data communications networks;
- ANSI-C-37.90: Standard for Relays and Relay Systems Associated with Electric Power Apparatus;
- IEC 60068: Environmental testing;
- IEC 60255: Measuring relays and protection equipment;
- IEC 61000: Electromagnetic compatibility (EMC);
- IEC 61968: Application integration at electric utilities – System interfaces for distribution management;
- NISTIR 7628: Guidelines for Smart Grid Cyber Security;
- NEMA SG-IMA 1-2009: Requirements for Smart Meter Upgradeability;
- SRSP-504: Technical Requirements for Radio Paging Systems Operating in the Band 929-932 MHz;
- CAN/CSA-B72-M (R2003): Installation Code for Lightning Protection Systems;
- GT-T-12.01.03.C: Grounding Standards for Hydro-Québec Telecommunications Installations;
- S37-01 (R2006): Antennas, Towers, and Antenna-Supporting Structures;
- Health Canada – Safety Code 6 (2009): Limits of Human Exposure to Radiofrequency Electromagnetic Energy in the Frequency Range from 3 kHz to 300 GHz;
- ISO 27002: Information technology – Security techniques – Code of practice for information security management.

Hydro-Québec Standards:

- D-25-05: Hydro-Québec Distribution Safety Standards
- E-21-10: Low-Voltage Electric Service;
- F.21-02: Normalized Technical Price Quote for Approval by Hydro-Québec Distribution

[69] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04356.html
[70] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04545.html