<u>Coalition - Book of Documents 1 – Sustaining Capital</u>

1

5

METSCO
MAKING IT POSSIBLE

Reliability Projection Model (RPM)
Final Report & Conclusions

Prepared For:

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6

Executive Summary

Overview

METSCO Energy Solutions Inc. (METSCO) was retained by EPCOR Distribution & Transmission Inc. (EPCOR) to develop a model that quantifies medium-term reliability impacts of varying capital program mixes and magnitudes on the company's distribution system, and by extension, its customers. Once implemented, the model will assist EPCOR in optimizing its capital investment decision-making in light of the targeted nature and magnitude of reliability outcomes, along with other applicable operational and financial considerations.

The types of capital investments underlying the model include conventional equipment replacements as well as emerging technologies – namely the Distribution Automation (DA) and the Advanced Distribution Management Systems (ADMS) that the utility has piloted and/or contemplated. The scope of the modelled impacts was restricted to system-wide measures, namely SAIDI, SAIFI and CAIDI.

The essence of METSCO's inquiry entailed establishing statistical relationships between discrete types of capital investments, and the distribution system's ensuing reliability performance over the following ten years. Where statistical insights alone were not conclusive due to data availability or other pertinent factors, METSCO relied on its professional judgment and in-depth knowledge of industry best practices in the areas of reliability forecasting. The resulting Reliability Projection Model (RPM) is grounded in empirical analysis of EPCOR's historical outage data tracked in the company's SOLAR reliability database, asset inspection records from the IVARA asset management system, along with the information from the company's financial and geospatial databases, and insights extracted from the previously configured Asset Risk-Based Framework and corresponding results [11].

For clarity, neither this report, nor the RPM model that it supports advocate for a particular mix and/or nature of capital investments and operating expense, or any particular reliability performance levels. As such, the findings, observations and recommendations supplied herein are limited to the insights obtained from the analytical portion of the report that are meant to assist EPCOR in the future deployment of the model.

System Status Quo and Operational Implications

The 16 years of reliability data examined in the course of METSCO's study (2000-2015) showcase a general deteriorating trend in both SAIDI and SAIFI (that is, higher duration and frequency of outages as time progresses towards the present), notwithstanding some year-over-year variability that is expected in light of the distribution system's interaction with the natural environment. EPCOR's historical system-wide reliability performance, normalized by MED days, over the last sixteen years is shown in Figure E-1.

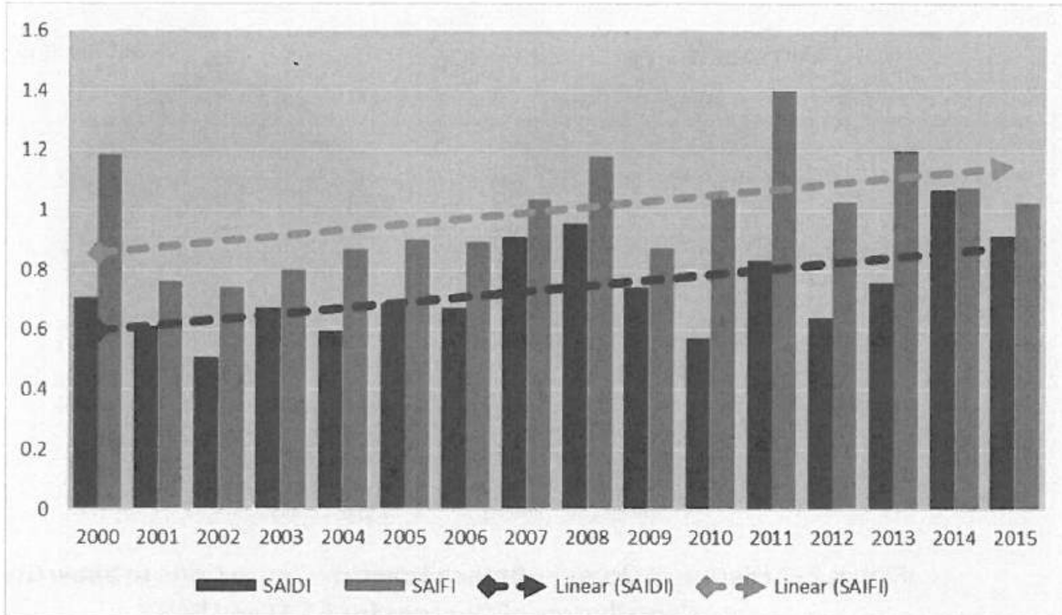


Figure E-1 2000-2015 historical system-wide SAIDI & SAIFI with Linear Trending to indicating deteriorating reliability.

As illustrated in Figure E-2, approximately 50% of all historical SAIFI and SAIDI levels come from Defective Equipment and Foreign Interference Cause Codes, using traditional Canadian Electricity Association (CEA) cause code nomenclature. Scheduled Outages, which are primarily a function of EPCOR's need to replace, upgrade, or otherwise service its existing asset base, are the third highest contributor to SAIDI specifically, and represent 15% of the total index value.

Figure E-3 showcases that underground cables are a single leading cause of both outage frequency and duration attributable to defective equipment, accounting for 52% of defective equipment SAIFI and 65% of defective equipment SAIDI, respectively.

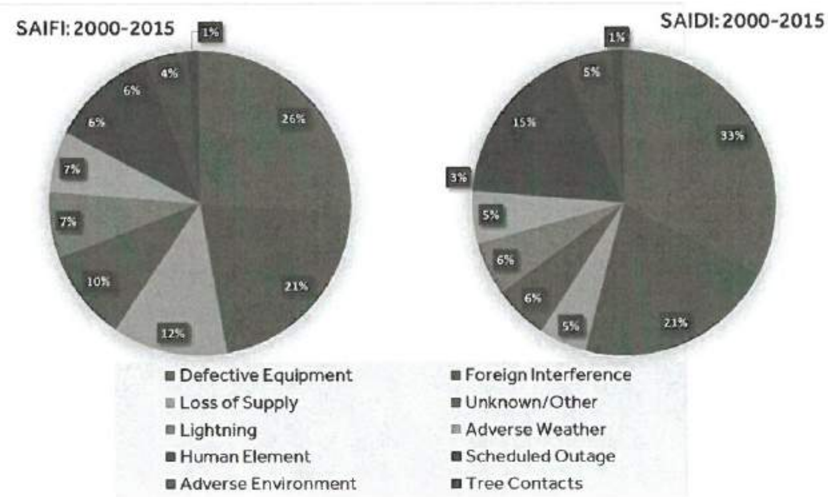


Figure E-2 Historical Outages Broken Down by Cause Code to Show Greatest Contributors of Outages for SAIFI and SAIDI

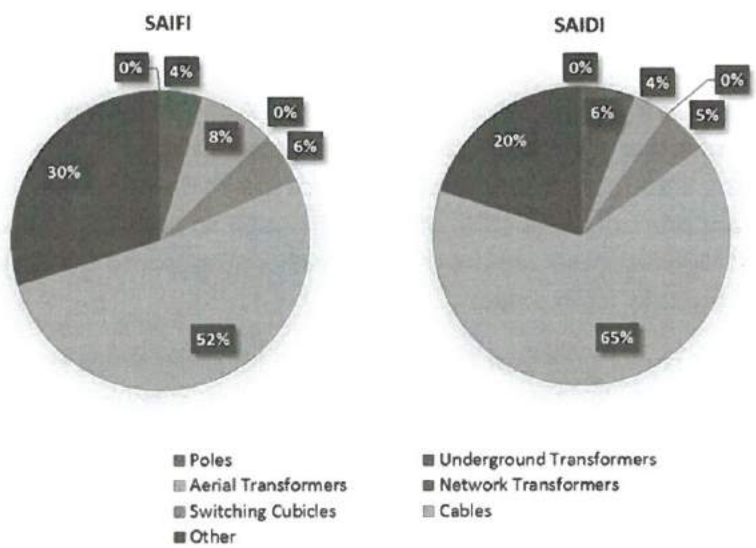


Figure E-3 Historical Defective Equipment Outages broken down by asset class

For the purposes of its analysis and the ensuing model calibration, METSCO separated all outage cause codes into Controllable and Non-Controllable Outages, depending on whether and to what extent the locus of outage control rests with the distributor and its decisions, including those taken years ahead of the outage event. Using the standard CEA cause code framework, METSCO deemed Controllable cause codes as being those outages attributable to Defective Equipment and Scheduled Outage. In METSCO's assessment, these are the only two categories where the distributor can be seen as being caused by internal factors and being fully in control of preventing the outages through a

9

variety of operating and investment decisions. Conversely, the remaining outage cause codes, namely Adverse Environment, Adverse Weather, Foreign Interference, Human Element, Lightning, Loss of Supply, Tree Contacts, and Unknown/Other are characterized as Non-Controllable. The drivers behind these outage categories entail circumstances, the physical manifestations of which cannot be reasonably expected to be predictable and/or sufficiently avoidable by the distributor through capital investments – the focus of this report and the model.

Separating EPCOR's historical SAIFI and SAIDI along the lines of controllability, as shown in Figure E-4, reveals that non-controllable outages remain a dominant factor behind the utility's overall system reliability performance, accounting for 70% of SAIFI and 57% of SAIDI respectively. These results indicate that while defective equipment and scheduled outages can continue to be managed, there remains a sizeable proportion of externally driven non-controllable outage events that either cannot be mitigated at all, or can only be partially mitigated at best. This insight, highlights the significance of the nature, timing and magnitude of capital investments to replace the aging equipment, if the curtailment of the overall reliability trend is to be attained.

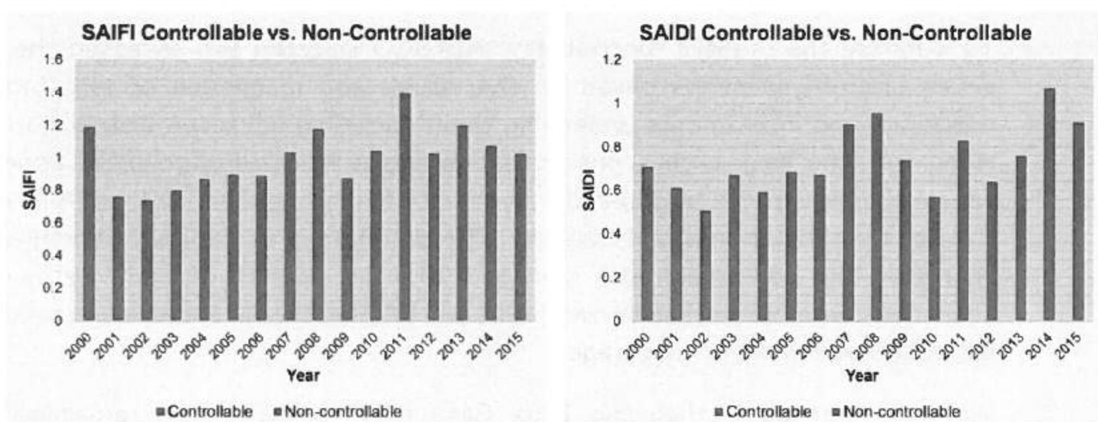


Figure E-4 – Breakdown of Historical SAIFI/SAIDI (2000-2015) into Controllable & Non-Controllable Categories

EPCOR's historical reliability analysis summarized above illustrates some the challenges and tradeoffs that the utility is facing in its efforts to manage system performance:

- Deteriorating system reliability trend that requires effective capital planning and implementation in order to be curtailed or reversed;
- The majority of events are driven by external factors that are predominantly outside of the utility's control and are only subject to partial mitigation;
- Defective equipment is the single largest cause of controllable outage causes, requiring capital-intensive asset replacement programs to be addressed;

- While driving more than half of reliability issues caused by Defective Equipment, underground cables are among the costliest assets to replace;
- Reducing the aggregate reliability indices through intervention to address controllable outage causes requires significant capital investments levels;
- A short-term tradeoff of asset replacement efforts is an increase in Scheduled Outages, which account for the third highest driver of outage duration.

The Model and Representative Scenarios Considered

METSCO's analysis of EPCOR's outage statistics separated by cause codes and cross-referenced with pertinent geospatial, financial and asset management data led to development of a predictive model grounded in statistically-derived correlations between system investments and outage occurrences for controllable causes, along with statistical projections of outages caused by events not correlated with the distributor's decisions.

METSCO notes that the RPM model has been developed to define a ten-year forecasted *trend* of distribution system reliability performance, whereas the actual reliability performance can vary from the predicted trend year-over-year.

To illustrate the model's functionality, METSCO selected and assessed the impact of seven discrete scenarios based on the nature and magnitude of targeted reliability outcomes and investments underlying them (including advanced distribution systems), along with the base case scenario that entails a Run-to-Failure (RTF) approach. The scenarios range from a targeted improvement of 10% to either SAIDI or SAIFI values over the ten-year timeframe and utilizing different modes of capital intervention, to the scenarios that contemplated a managed 10% degradation of both metrics. Midpoint scenarios contemplate maintaining SAIDI and SAIFI at the recent levels, representing the latest available three-year average.

We note that other than the Base Case (RTF) scenario, the remaining scenarios contemplate changes to SAIDI or SAIFI separately, as METSCO sees it as generally cost-prohibitive for EPCOR to materially affect frequency values (SAIFI) at a consistent rate. We leave the discretion as to which of the two metrics is seen as more important to pursue up to EPCOR's customer base and management. The scenarios are summarized in the following table:

#	Scenario	Scenario details	Summary Results
1	Run-to-failure	Base case scenario used for comparisons with other contemplated approaches.	This scenario yielded an increase (deterioration) in SAIDI of 25% and in SAIFI of 24% for the forecasted years 2016 to 2025 relative to the most recent three-year average. Requisite investments for the next ten years are approximately $29M annually, with a breakdown of $25M in capital programs and $4M in operating expenses
2	Maintain SAIFI with like-for-like asset replacement	The objective is to maintain outage frequency levels at the last three-year average by proactively replacing the assets only, without implementing the DA, ADMS and other reliability driver programs.	The investment program required to maintain the SAIFI performance metric would result in $132M in capital programs and $4M in operating expenses. The total spending over the 10-year horizon amounts to $1.36B, which includes both Capital and Operating programs.
3	Maintain SAIFI with DA and other investments	The objective is to maintain reliability (last three-year average) by proactively replacing the assets, and implementing DA, ADMS and key reliability driver programs	The investment program required to maintain the reliability performance (SAIFI and SAIDI) would result in $971M in capital programs and $49M in operating expenses The total spending over the 10 year horizon amounts to $1.02B, which includes both Capital and Operating programs.
4	Maintain SAIDI with DA and other investments	The objective is to maintain only SAIDI (last three-year average) by proactively replacing the assets, and implementing DA and ADMS system-wide projects. Assumption is to relax SAIFI metric as it requires significant investments to maintain SAIFI	The investment program required to maintain the SAIDI performance metric would result in $264M in capital programs and $39M in operating expenses The total spending over the 10-year horizon amounts to $302M, which includes both Capital and Operating programs.

5	Improve SAIDI by 10%	The objective is to improve only SAIDI performance in by 10% in 10 years (last three-year average) by proactively replacing the assets, and implementing DA and ADMS system-wide projects. Assumption is to relax SAIFI metric as it requires significant investments even to maintain SAIFI.	Investments required to improve reliability by 10% for the next ten years are approximately $475M in capital programs and $43M in operating expenses.
6	Worsen SAIDI by 10% in 10 years	The objective is to allow a maximum of 10% worsening of system reliability performance in SAIDI (last three-year average) by proactively replacing assets, and implementation of DA, ADMS and other key reliability driver programs	Investments required to degrade reliability by no more than 10% for the next ten years are approximately $262M in capital programs and $39M in operating expenses.
7	Improve only SAIFI by 10%	The objective is to improve only the SAIFI performance metric by 10% in 10 years (last three-year average) by proactively replacing assets, implementing ADMS, DA and other key reliability driver programs	Investments required to improve reliability by 10% for the next ten years are approximately $1.39B in capital programs and $69M in operating expenses.
8	Worsen SAIFI by 10%	The objective is to allow a maximum of 10% worsening of system reliability performance in SAIFI (last three-year average) by proactively replacing the assets, and implementing DA and ADMS system-wide projects.	Investments required to degrade reliability by no more than 10% for the next ten years are approximately $483M in capital programs and $47M in operating expenses.

Table 1- Investment Scenario analysis

When viewed as a continuum, the financial implications underlying each of the analyzed scenarios represent the range of financial implications underlying EPCOR's decision making with respect to future reliability outcomes. As stated above, the scenarios were selected on the basis of METSCO's assessment of what entails a reasonable range of potential options that the utility can consider. The RPM model provides the utility with the discretion and capability to assess other combinations of targeted outcomes and investment types.

Total capital spending needs for each of the scenarios discussed Figure E5 The detailed discussion of the assumptions and approaches underlying each scenario are outlined in the sections that follow.

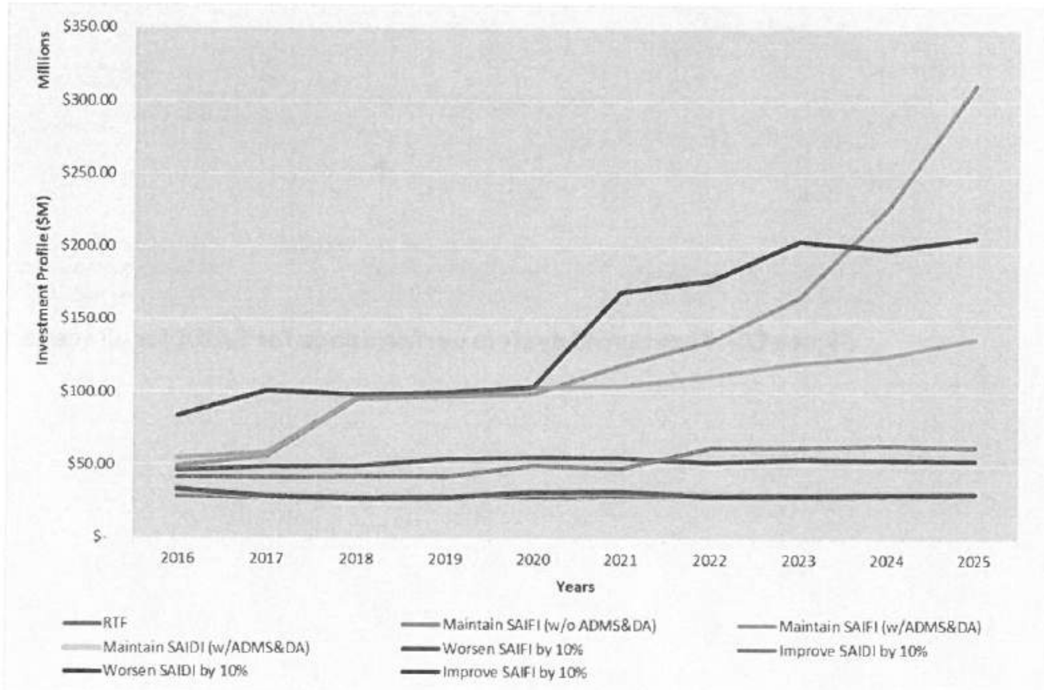


Figure E5 – Total Capital Investment for Scenarios Considered

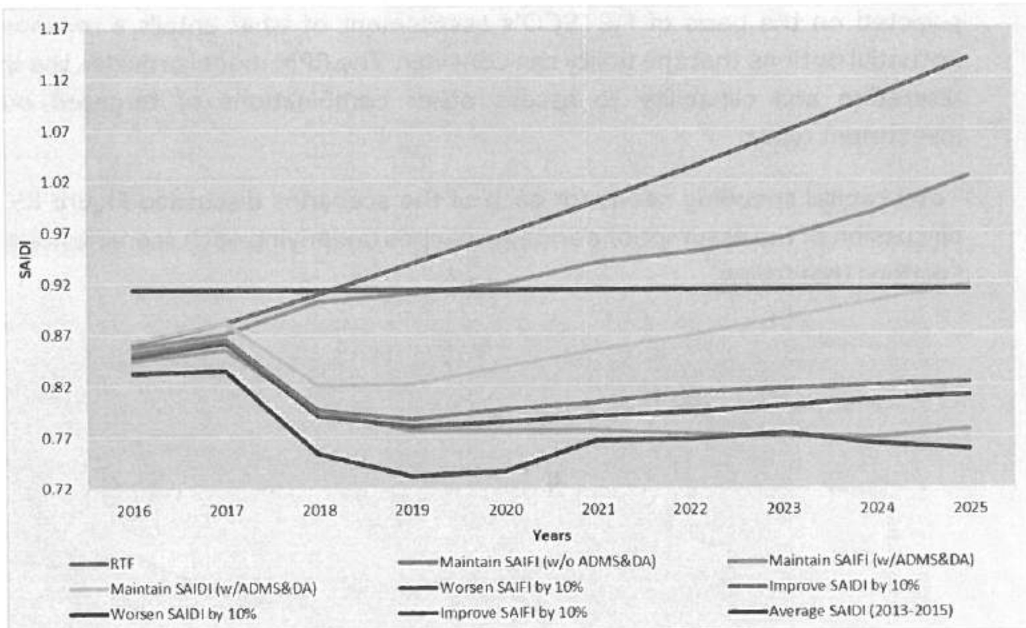


Figure E6– Forecasted system performance for SAIDI for all scenarios

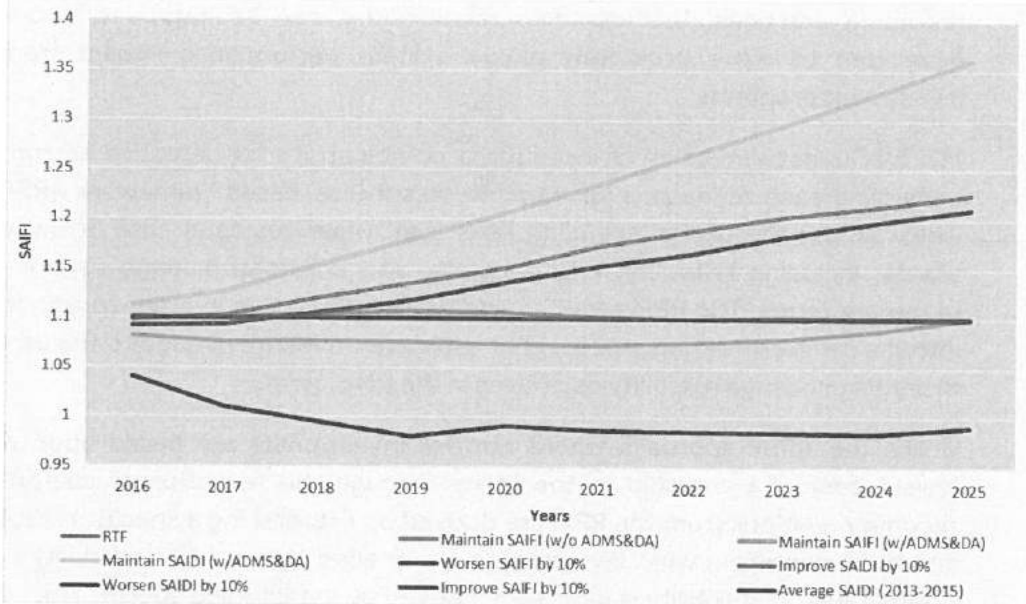


Figure E7 Forecasted system performance for SAIFI for all scenarios

Scenario	Investments
Run-to-Failure	$289M
Maintain SAIFI with like-for-like asset replacement	$1,361M
Maintain SAIFI with DA and other investments	$1,020M
Maintain SAIDI with DA and other investments	$302M
Improve SAIDI by 10%	$519M
Improve SAIFI by 10%	$1,464M
Worsen SAIDI by 10%	$302M
Worsen SAIFI by 10%	$530M

Table 1-I Ten-Year Total Spending – Capital and Operating Expenses-per scenario.

METSCO notes that the RPM model only considered those investment programs where sufficient data was available in order to apply statistical regression techniques, or a meaningful relationship between the investment type and reliability could be hypothesized on the basis of experience and engineering judgment. Accordingly, certain EPCOR capital investment portfolios (e.g. external relocations, fleet upgrades, safety and environmental protection investments, improvements to IT systems, facilities upgrades), should be added to the above investment scenarios if the goal is to evaluate the utility's total capital needs.

In the spirit of continuous improvement, METSCO's report contains a number of specific recommendations related to its recording practices that EPCOR can implement in order to further refine the current data within systems like SOLAR and IVARA. With enhanced event recording practices, the identified relationships can be improved upon and further developed to more accurately gauge system performance impact from conducted investment programs.

METSCO's determination of investment combinations for defective equipment changes underlying each scenario is based on its Asset Risk-Based Framework ARBF report [11], which shows the capital spending level that minimizes total cost of ownership of the assets, including reliability, environmental and collateral damage risks if quantified in monetary terms. The RPM provides additional information in order to gain further insight into the decision-making process that estimates investment needs if the utility decides to maintain or change reliability objectives in the long-term.

Unlike the ARBF approach where optimal investments are based upon delivering the lowest cost of ownership to the utility through the reduction of customer risks, the recommendations from the RPM are derived by establishing a specific reliability objective and then identifying what investments are needed to meet this reliability objective. The optimal level of reliability is ultimately derived by establishing specific risk *outcomes*, and then deriving the investment program that will meet these outcomes.

As it is recommended that the Asset Risk-Based Framework results should be updated on an annual basis [11] to account for changes to the asset population as well as accounting for the availability of up-to-date asset data records, results from the Reliability Projection Model will similarly have to be updated on an annual basis to account for the adjustments to the defective equipment cause code as well as to account for new initiatives aiming to improve system reliability performance.

Possible key reliability drivers were investigated, including wind, precipitation and temperature data for the City of Edmonton which was collected from Environment Canada. However, due to the aforementioned irregular reporting of the sub-cause code data, individual correlations between these drivers and the sub-cause codes could not be established. Therefore, an overall 15-year average trend was used to project all three of these sub-cause code categories.

3.3.2 Analysis and Results

Various key reliability drivers, including weather-related drivers, were explored for the Adverse Weather cause code. When looking at precipitation, as illustrated in Figure 15, it was observed that those years with higher amounts of precipitation did not result in an increase in Adverse Weather events. Similarly, a greater frequency of extreme wind days did not result in an increase in Adverse Weather events, as illustrated in Figure 16.

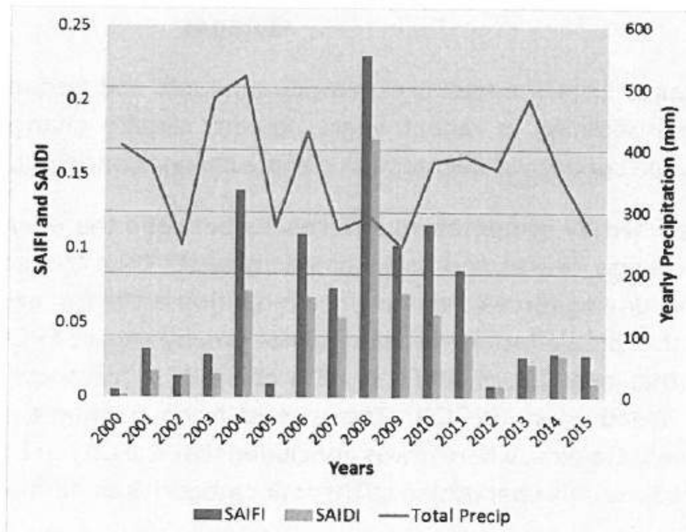


Figure 15 – Yearly Precipitation in Edmonton compared to Adverse Weather Outages

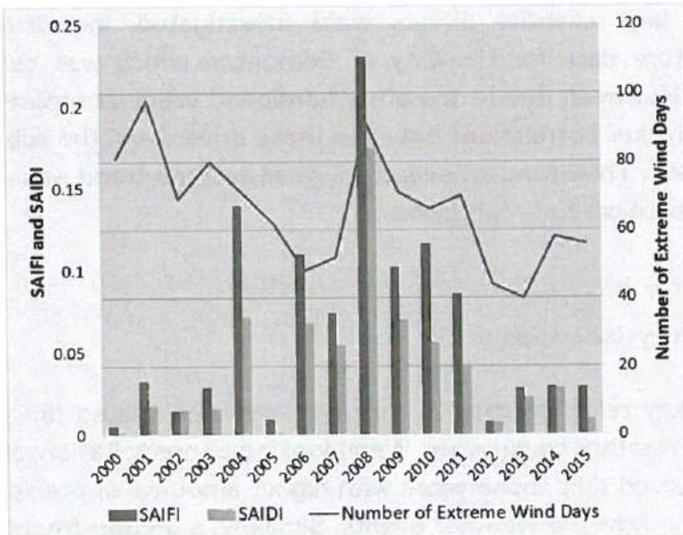


Figure 16 – Yearly Extreme Wind Days in Edmonton compared to Adverse Weather Outages

These figures illustrate that precipitation amounts and frequency of extreme wind days have been declining in recent years. Recent climate change research suggests that average wind speeds will decrease as climate change continues.

Wind is caused by temperature differences between the equator and the Earth's poles. Climate change causes the poles to warm faster than the equator, which slows global convective driving forces, resulting in a reduction in the frequency of extreme wind days[3]. The fact that precipitation and wind do not greatly impact EPCOR's outages is in line with the fact that only 7% of SAIFI and 5% of SAIDI in historical outages are attributed to Adverse Weather at EPCOR. This can also be further explained via a study from Environment Canada, where it was concluded that the City of Edmonton within the top ten of least stormy cities pertaining to the four categories as illustrated in Table 5[4].

Category	Days a Year	Placement in Top 10
Fewest Heavy Rainstorms	2.3	5
Fewest Severe Snowstorms	1.7	6
Fewest Thunderstorms	18.8	10
Fewest Strong Winds	0.5	3

Table 5: City of Edmonton's Rank amongst Canada's Top Ten Least Stormy Cities[3]

3.7 Tree Contacts

The Tree Contacts cause code refers to those outage events due to faults caused by trees or tree limbs contacting energized circuits [2]. There are no further sub-cause codes for this projection.

3.7.1 Projection Approach

Figure 32 illustrates the individual mechanics for the Tree Contacts projection.

Figure 32 – Summary of Tree Contacts Projection Mechanics

No key reliability drivers could be identified due to lack of high confidence correlations to the historical tree contact data. As a result, a 15-year average projection was applied.

3.7.2 Analysis and Results

As tree trimming activities were identified as a possible key reliability driver, EPCOR's associated investments for tree trimming were compared to historical tree contact events. From this analysis, no correlation could be observed. Part of the reason for this lack of correlation could be because tree contacts have occurred very infrequently within EPCOR's system compared to other cause codes, and only represent 1% of the total SAIFI and SAIDI metrics, as first illustrated in Figure 7. In addition, tree trimming investments were only available from 2010 and onwards. The small sample sizes of both tree contact and tree trimming data would impact efforts to produce a high-confidence correlation between these two variables. Therefore, the final projection was based on an average of the historical 15-year period. The average was used for the projection because there was no significant correlation shown when doing a linear or logarithmic trend.

Other possible key reliability drivers were also explored, including precipitation and extreme wind. When looking at precipitation as a contributing factor to Tree Contacts, as illustrated in Figure 33, it was seen that years with higher precipitation did not result in a greater frequency of Tree Contacts events. Similarly, as illustrated in Figure 34, years with a greater frequency of extreme wind days did not translate into a greater amount of Tree Contact-related events.

6 Investment Scenario Analysis

Analysis of EPCOR's historical reliability data combined with internal and external factors reveal the challenges that the utility is facing in order to manage the system performance:

- Deteriorating system reliability trend that requires effective capital planning and implementation in order to be curtailed or reversed;
- The majority of events are driven by external factors that are predominantly outside of the utility's control and are only subject to partial mitigation;
- Defective equipment is the single largest cause of controllable outage causes, requiring capital-intensive asset replacement programs to be addressed;
- While driving more than half of reliability issues caused by Defective Equipment, underground cables are among the costliest assets to replace;
- A short-term tradeoff of asset replacement efforts is an increase in Scheduled Outages, which account for the third highest driver of outage duration;
- While technologies like ADMS and DA represent cost-effective means of reducing outage duration, EPCOR's experience with them to date is limited, while the need to replace aging assets remains.
- Reducing the aggregate reliability indices through intervention to address controllable outage causes requires significant capital investments levels.

To illustrate the model's functionality, METSCO selected and assessed the impact of seven discrete scenarios based on the nature and magnitude of targeted reliability outcomes and investments underlying them (including advanced distribution systems), along with the base case scenario that entails a Run-to-Failure (RTF) approach. The scenarios range from a targeted improvement of 10% to either SAIDI or SAIFI values over the ten-year timeframe and utilizing different modes of capital intervention, to the scenarios that contemplated a managed 10% degradation of both metrics. Midpoint scenarios contemplate maintaining SAIDI and SAIFI at the recent levels, representing the latest available three-year average. We note that other than the Base Case (RTF) scenario, the remaining scenarios contemplate changes to SAIDI or SAIFI separately, as METSCO sees it as generally cost-prohibitive for EPCOR to materially affect both system outage duration and frequency values at a consistent rate. We leave the discretion as to which of the two metrics is seen as more important to pursue up to EPCOR's customer base and management.

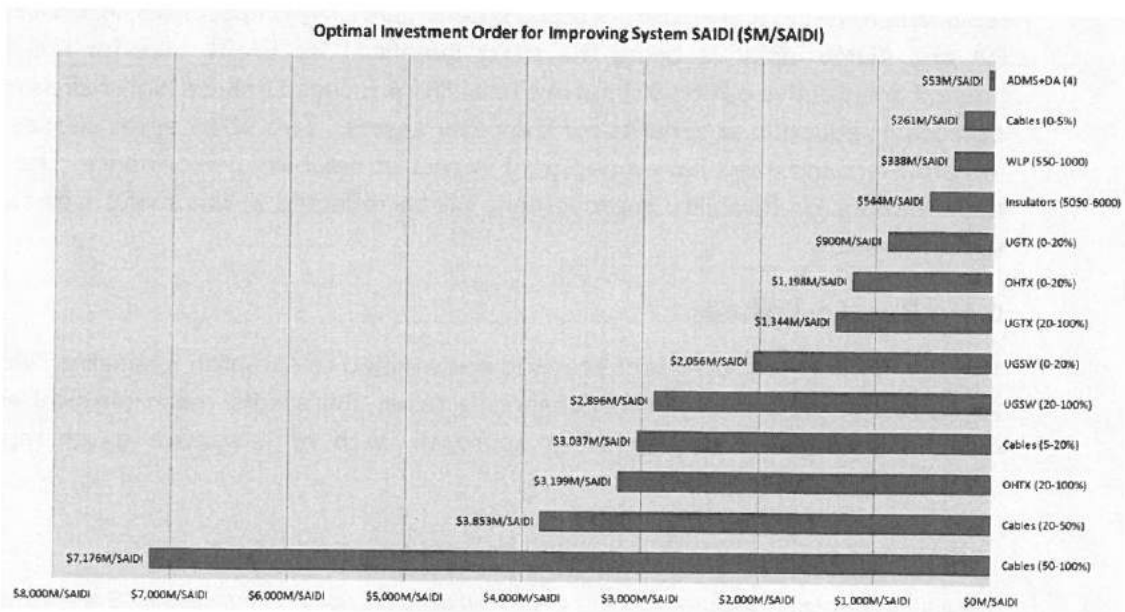
The scenarios are divided in a manner, such that the impacts of DA initiatives can be separately evaluated to see if these system-wide improvements serve as effective alternatives when compared to only asset replacement programs. Implementation of ADMS and DA will help to minimize outage duration times, thereby heavily improving SAIDI, but will have zero impact on the frequency of outages – SAIFI. Therefore, the study analyzed additional scenarios with an objective to improve SAIDI, allowing the SAIFI metric to degrade and conversely, scenarios were developed in order to bring improvements in SAIFI with degradation of SAIDI.

The reliability scenarios analyzed in this study are outlined below:

1. Run-To-Failure
2. Maintain SAIFI with like-for-like asset replacement
3. Maintain SAIFI with DA and other investments
4. Maintain SAIDI with DA and other investments
5. Improve SAIDI by 10%
6. Improve SAIFI by 10%
7. Worsen SAIDI by 10%
8. Worsen SAIFI by 10%

These scenarios provide EPCOR with a varying outlook on system reliability such that they are able to devise their own asset management plans to meet the objectives set for its electric distribution system.

Provided below is a cost benefit analysis of each of the various investment options that are available to EPCOR when looking to impact their reliability performance. Each metric has been developed by comparing Run-to-Failure (RTF) with respect to the performance of the investment option. The figure below provides the analysis showing the cost in dollars required to reduce system wide SAIFI and SAIDI by one (1) for the various key reliability drivers established within the framework.



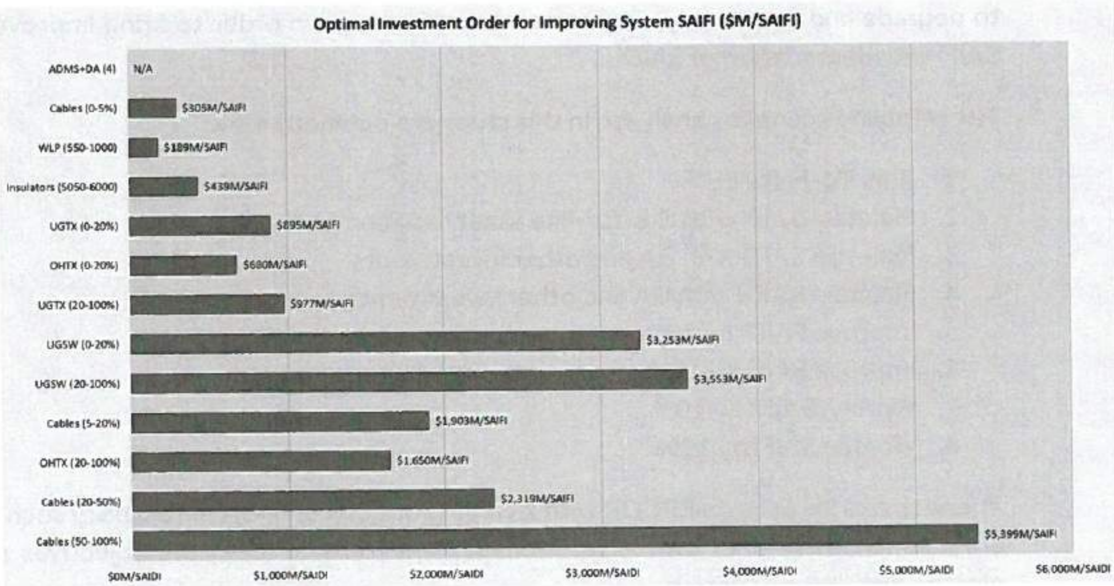


Figure 58 Cost Benefit analysis of All Key Reliability Driver Programs[2].

Asset like-for-like replacement strategies have been graded to analyze an impact of replacing the assets with the highest risk costs first, with a diminishing marginal return on reliability improvement with the following assets. For cables, the grades are 0%-5%, 5%-20%, 20%-50% and 50%-100%, while the other assets have two grades 0%-20% and 20%-100%. System improvement programs such as DA and ADMS, Wildlife Protector replacement (WLP) and Insulators replacement have a high impact on SAIDI/SAIFI, with the DA and ADMS initiative being the most beneficial for SAIDI. Like-for-like strategies present an effective option to improve reliability if focused only on high-risk assets, with a significant reduction in benefits for the other assets. Two other asset classes, network transformers and poles have a negligent impact on reliability performance. The impact of these options on reliability improvement will be reflected in the analysis of each of the scenarios below.

6.1 Run-to-Failure

The Run-to-Failure investment scenario was studied to establish a baseline "worst case" scenario. The objective of this scenario is to let the assets reach physical end-of-life conditions as per a run-to-failure approach, with no proactive asset replacement

[2] System improvement initiatives: ADMS-DA – Advanced Distribution Management System and Distribution Automation. WLP – Wildlife Protectors, Insulators. Like-for-like asset replacement strategies: Cables – Underground Cables, UGTX – Underground Transformers, OHTX – Overhead Transformers, UGSW – Switching Cubicles.

management strategies conducted, and with system performance degrading along with the aging infrastructure.

Figure 59 and 60 below provides the forecasted full system reliability results, for SAIDI and SAIFI, in the Run-to-Failure investment scenario.

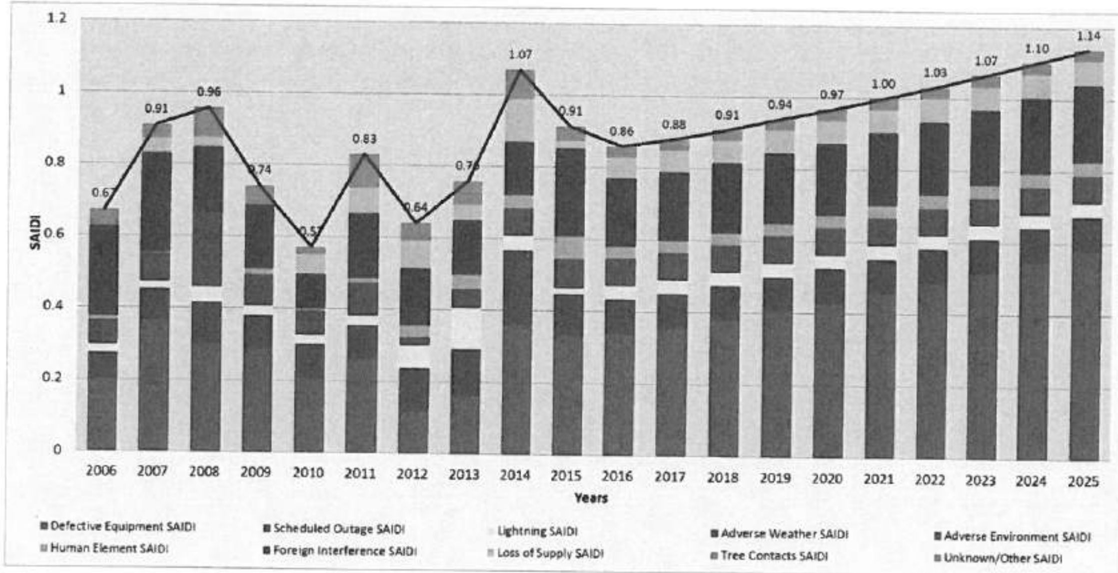


Figure 59 – RTF scenario: SAIDI Results

25

2

27

NAVIGANT FIRST QUARTILE CONSULTING

Distribution Unit Cost Benchmarking Study

Pole Replacement and Substation Refurbishment

Prepared for

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October 19, 2016

EXECUTIVE SUMMARY

In the Ontario Energy Board's (OEB's) decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, the Board directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". Hydro One was also directed to "report on the results of this work with the corresponding analysis as part of its next rates application". Through a competitive procurement process, Hydro One Networks Inc. (Hydro One) engaged the consortium of Navigant Consulting Ltd. (Navigant) and First Quartile Consulting (1QC) to conduct this benchmarking study.

This report provides an overview of the approach, including the processes of selecting and recruiting utilities to participate in the study, assembling appropriate performance metrics, and gathering and analysing the data. The study provides insights into both the costs incurred by Hydro One and the practices used for the execution of pole replacement and substation refurbishment. Primary findings from the study for both the pole replacement and station refurbishment activities are presented below.

Pole Replacement

1. Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles.
2. Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections with some light physical inspections, while the others typically perform more rigorous physical inspections and testing.
3. The replacement rate for Hydro One is slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest; on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group.
4. Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone premature replacement of poles.

Substation Refurbishment

1. Station refurbishment activities are varied within and across utilities.
2. Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.
3. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.
4. Navigant and First Quartile Consulting believe that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.
5. Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.
6. Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.

Recommended Actions

In its request for proposals, Hydro One indicated that the study should produce recommendations that Hydro One could act upon to close gaps to best practice and improve the efficiency of its operations. Several recommendations were developed for each of the two areas under study.

Pole Replacement

The key recommended actions for pole replacement are outlined below.

1. Consider modifying the pole replacement program to include more complete pole inspections (sound, bore, excavation) and a longer (approximately 10-year) inspection cycle – the OEB would need to approve the change in inspection cycle.
2. Expand the existing centralized program management and pole selection approach to cover 90-95% of the replacement / refurbishment work on poles in a given year, leaving the remainder to be guided by the local staff while still meeting the centralized strategy and replacement criteria
3. Where geography and/or pole density permit, consider the use of dedicated pole replacement crews.
4. Consider modifying the program to include a rigorous pole refurbishment option, when appropriate.

Substation Refurbishment

The key recommended actions for substation refurbishment are outlined below.

1. Consider implementing a formal data governance process for equipment performance and maintenance data, and incorporating that information into the asset condition scoring and project planning process.
2. Enhance cost and work completion reporting for individual projects, and implement a formal change control process.
3. Develop and implement a more comprehensive set of key performance indicators including in-progress project cost performance measures and assessments of project/program impacts on substation reliability, maintenance costs and overall asset health.

1. INTRODUCTION

In the OEB's decision in EB-2013-0416/EB-2014-0247 on Hydro One's distribution rates for 2015 to 2019, it directed Hydro One to "to conduct an external benchmarking study on the unit cost of its pole replacement and station refurbishment programs against other utilities as well as carry out an internal trend analysis to show the variability of these unit costs over time (year over year)". Hydro One was also directed to "report on the results of this work with the corresponding analysis as part of its next rates application".

1.1 Study Objectives

Hydro One engaged Navigant and First Quartile Consulting to design and implement a robust and replicable benchmarking study of Hydro One's distribution costs.

The benchmarking study was designed to:

- Include an appropriate group of utilities to compare Hydro One against, taking into account a number of characteristics, including asset demographics, geography, customer characteristics, etc.;
- Quantify and evaluate Hydro One's practices and unit costs for distribution pole replacement and distribution substation refurbishments and substation replacements relative to the comparison utilities, taking into account cost drivers and differentiating characteristics;
- Ensure a common understanding of the comparison criteria through the use of clear definitions;
- Make recommendations on practices that could be augmented or adopted to improve efficiency; and
- Engage stakeholders in regards to the comparison group selection criteria, comparison metrics, and preliminary findings and recommendations.

1.2 Overview of Approach

The approach to the engagement included two analyses: a quantitative analysis and a qualitative analysis. Figure 1 provides a pictorial overview of the approach used for the project. As part of the study, the evaluation team determined which business and operational demographics were relevant to identify a representative comparison group given Hydro One's vast and disparate service territory. This work leveraged First Quartile Consulting's existing transmission and distribution benchmarking program participants as well as additional companies recruited specifically for this study.

Through the quantitative analysis, the evaluation team identified and collected the necessary data from Hydro One and the comparison utilities, normalised the data, and assembled statistical reports and comparisons. Through the qualitative analysis, the evaluation team explored cost variations, identified current and best practices, and identified gaps that ultimately led to recommendations on processes and practices that Hydro One could adopt to realise efficiency gains.

The study engaged and included stakeholders. Hydro One consulted with stakeholders regarding the terms of reference for this study. Stakeholders then had the opportunity to review and provide comments at the beginning of the study on the proposed methodology and selection of the comparison group. Finally, they commented on the preliminary results, prior to the evaluation team finalising the study.

America were identified and evaluated for their usefulness as part of the comparison group. As a result, 29 North American Utilities were approached to participate in the study.

Figure 4. Comparison Utilities Targeted for Participation

8 Canadian Utilities	21 U.S. Utilities
• Large provincial utilities from across Canada	• Large utilities
• Mix of local distribution companies in Ontario	• Previous willingness to participate in similar studies

Responses (combined) were received from 20 organizations. Those not responding cited various reasons for not participating:

- Lack of interest;
- Insufficient resources; and
- Competing priorities.

Not all of the utilities agreed to participate in both parts of the study. A few contributed data only for the pole replacement part of the study, a few participated only in the substation refurbishment part, while the majority participated in both portions. Together, they provide a reasonable representation of the North American utility industry, and a viable comparison group for Hydro One.

A concerted effort was made, as requested by stakeholders, to include more Canadian utilities. However, because there is no requirement for them to participate, and the effort for them to participate is significant, only a few Canadian utilities agreed and provided data for the study. As shown in Figure 5, the utilities in the comparison group are located throughout Canada and the U.S. There are several large companies, some smaller ones, with regulatory circumstances and weather patterns similar and different from Ontario. The net result is a reasonably representative and useful comparison group.

Figure 5. Comparison Utility Service Territories

3. POLE REPLACEMENT BENCHMARKING RESULTS

The key findings of the pole replacement benchmarking study are provided below.

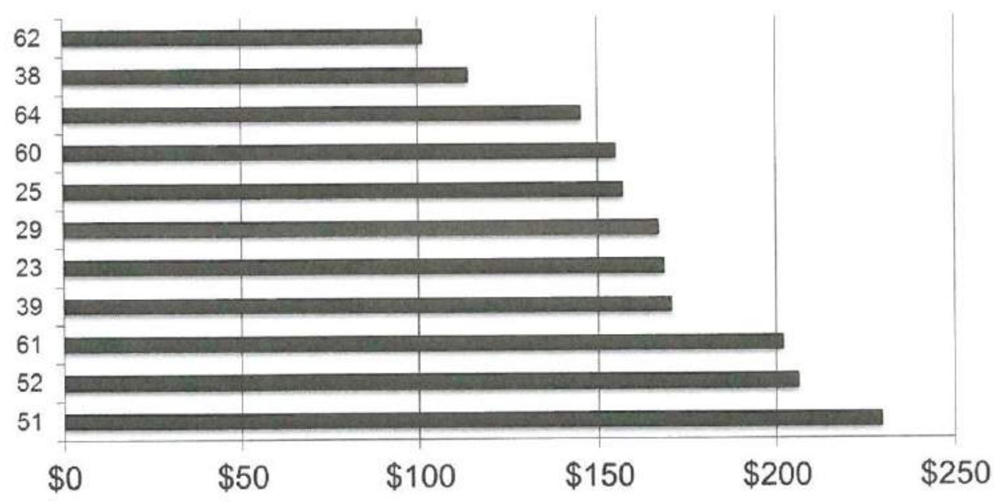
1. Hydro One's costs are in line with the average of the comparison group, with low unit costs for inspections and average costs for replacement of poles
2. Hydro One inspects its poles more frequently than most utilities, using mostly visual inspections, while the others typically do more rigorous physical inspections
3. The replacement rate has been slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest, and on average, eight years older than the rest of the utilities in the comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group
4. Hydro One does not employ a formal pole refurbishment program, whereas 13 of 17 companies in the comparison group do in an effort to postpone replacement of poles, and reduce lifecycle costs.

3.1 Cost Comparisons

The cost analysis portion of the study looked at pole replacement from several aspects – lifecycle costs per pole across all poles, unit costs per pole worked on in a year, and then costs of individual aspects of the pole program such as inspection costs, replacement costs, and refurbishment costs. Each of these is summarized below in a series of charts showing the resulting cost figures.

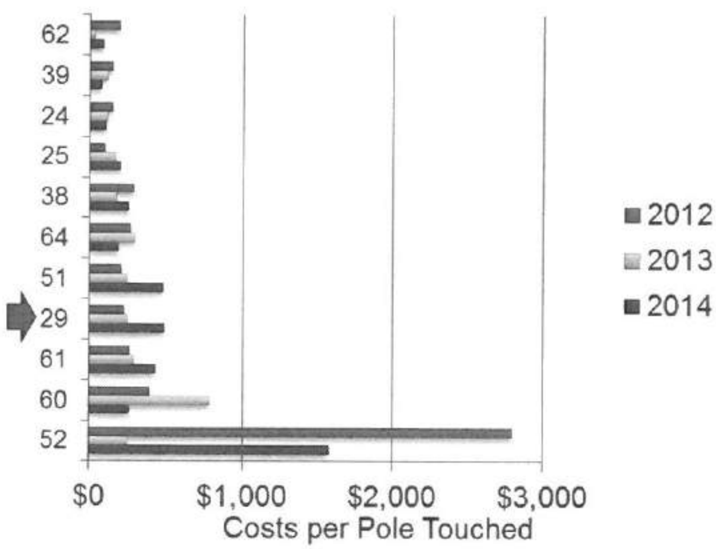
As shown in Figure 7, Hydro One demonstrates average life cycle costs. The most important factor in the life cycle cost is the original installation cost, but other factors such as the cost of inspections, the time between inspections, expected pole life, and others have influence as well.

Figure 7. Actual Annualized Life Cycle Costs per Pole per Year



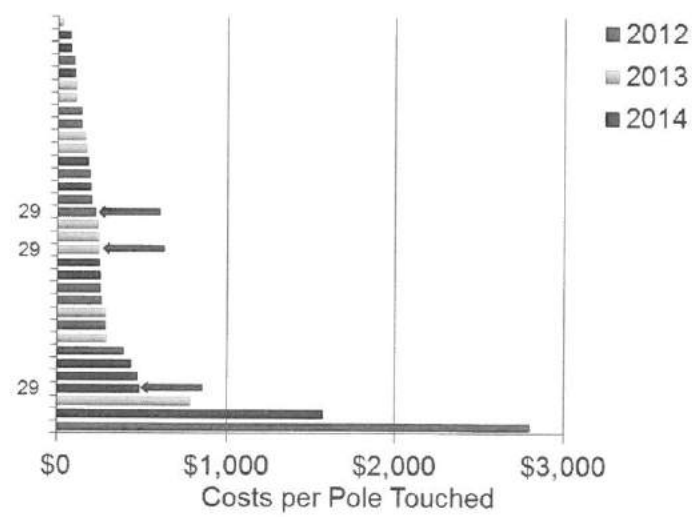
Another way to view pole program costs is through the unit cost of the poles touched (or treated) during an individual year. This is affected by the choices of how many poles to work on during a year, and what is done to those poles. "Poles touched" in this case is those inspected, refurbished, or replaced during the year, so depending on the mix of work done, the costs can vary year to year for an individual company. Three years of data were gathered for each of the participating companies, to allow understanding of these potential shifts from year to year. As with the life-cycle costs shown above, in this comparison, Hydro One again falls very near the mean of the comparison group.

Figure 8. Pole Program Costs Per Pole Touched Grouped by Company



Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

Figure 8. Pole Program Costs Ranked by Annual Spend



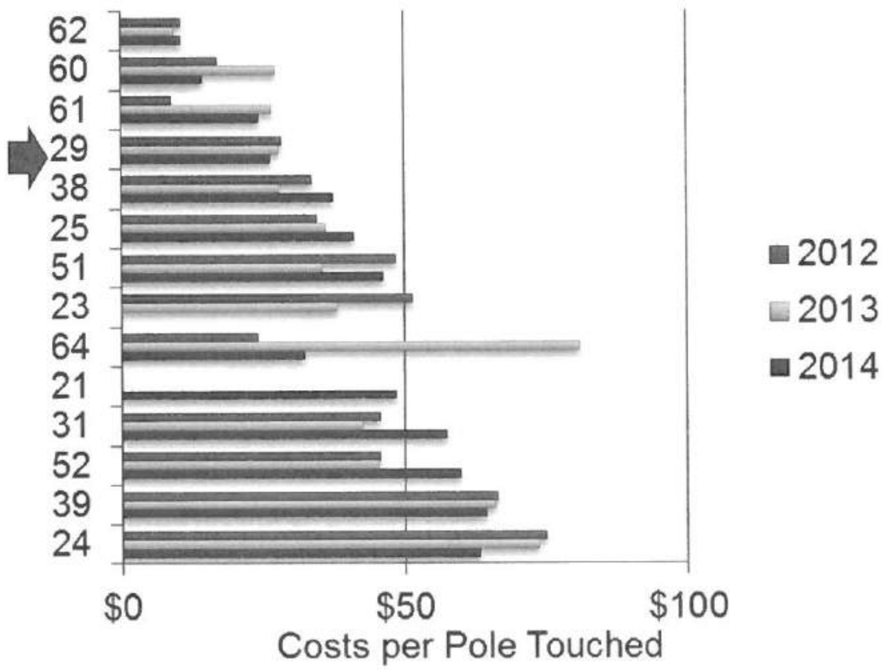
Note: In this comparison, pole touched means the total number of poles inspected, replaced, and refurbished.

3.2 Pole Inspection Costs and Frequency

Inspection costs are a function of what is done during the inspection. For example, is it a visual inspection, sound and bore, or other more complex physical inspection. Hydro One performs visual and light physical inspections on a shorter interval than most other companies (three to six years compared to 10 for the panel). Hydro One is the only company that does not use bore, excavation or ultrasonic methods on a dedicated schedule (seven to 20 years).

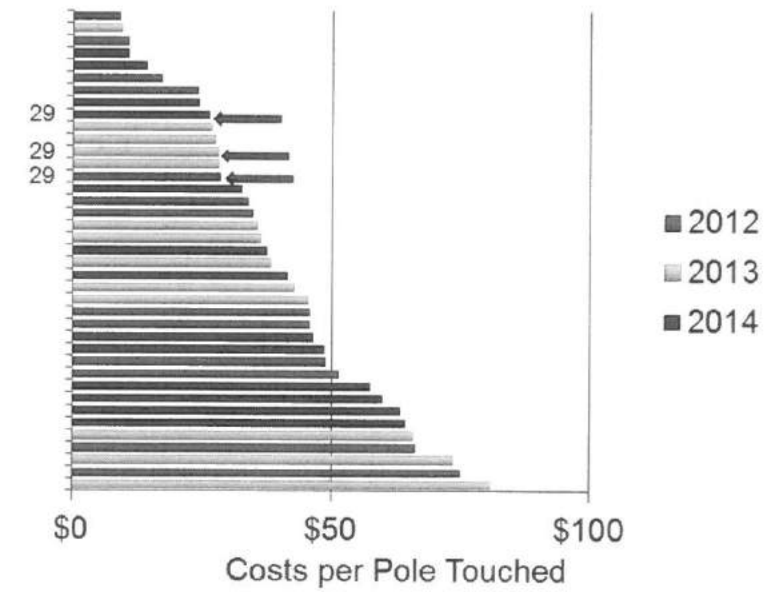
Overall, Hydro One conducts its inspections at a cost that is below the average of the comparison group. Hydro One costs are $27.60 per pole inspected, which is 29% lower per inspection compared to the mean of the panel.

Figure 9. Pole Inspection Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles inspected.

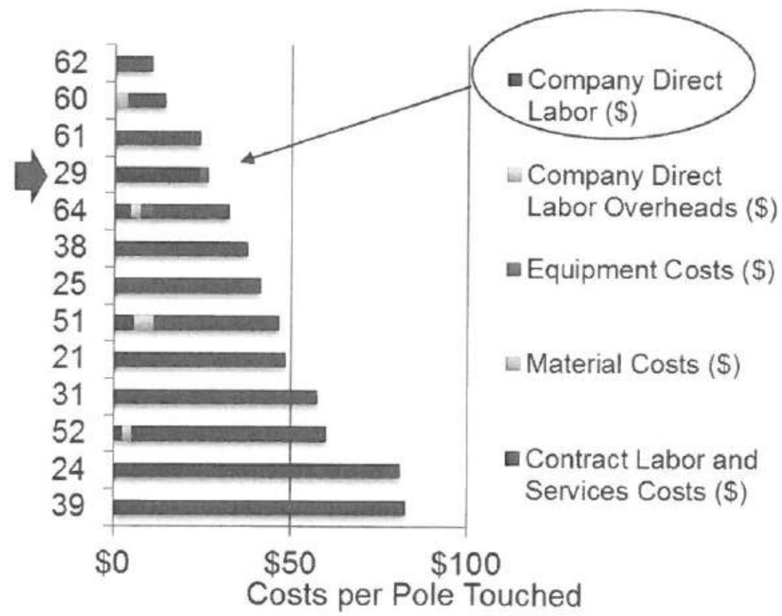
Figure 10. Pole Inspection Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles inspected.

Hydro One is the only company that performs more than 95% of inspections with in-house crews as compared to near 100% outsourced in other companies.

Figure 11. Pole Inspection Costs by Category

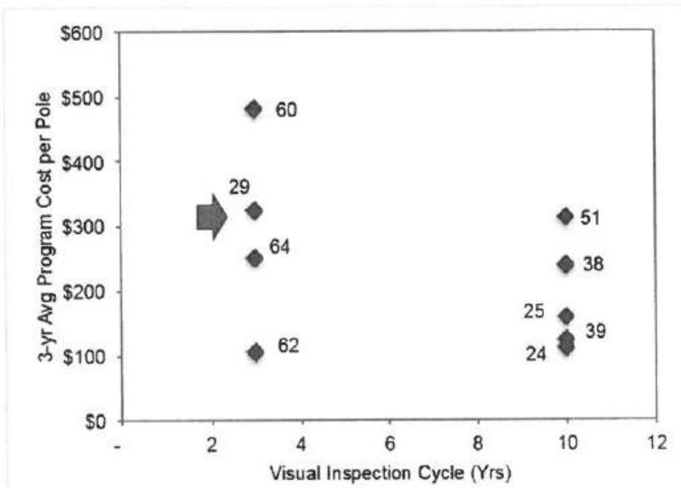


Note: In this comparison, pole touched means the total number of poles inspected.

3.2.1 Visual Inspection Cycle Time

Figure 12 shows the relative frequency of visual inspections and its impact on total pole replacement program costs. Where companies provided a range, the lower end of the range is represented in the figure. The frequency of inspections has only a modest impact on total program costs, since the majority of program costs are driven by pole replacements.

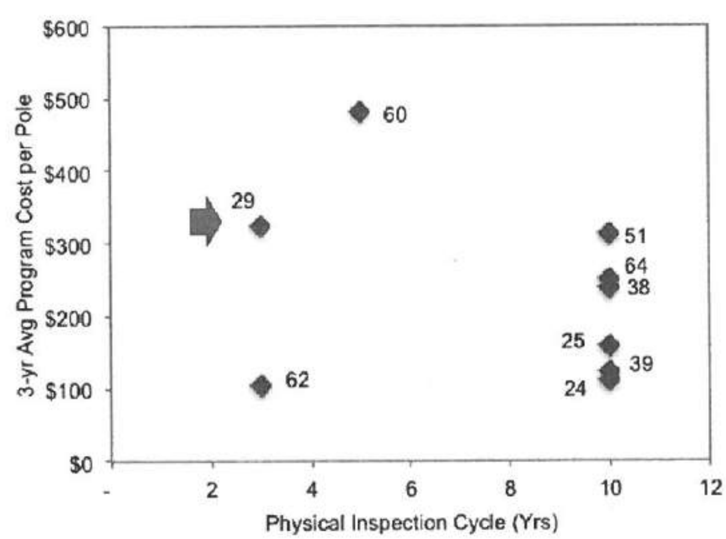
Figure 12. Visual Inspection Cycle Frequency



3.2.2 Physical Inspection Cycle Time

Though Hydro One doesn't have a comprehensive program for physical inspections, for those that are done, the cycle time is relatively short in comparison to the benchmark panel.

Figure 13. Physical Inspection Cycle Frequency



3.3 Replacement Rates and Pole Age

Hydro One has historically replaced its poles at a slower rate than other utilities. This fits with its planned longer life of the poles than other utilities in the comparison group. The net result is that the average age of Hydro One's wood poles is the oldest in the panel, at 37 years.

Figure 14. Age Profile of Wood Poles

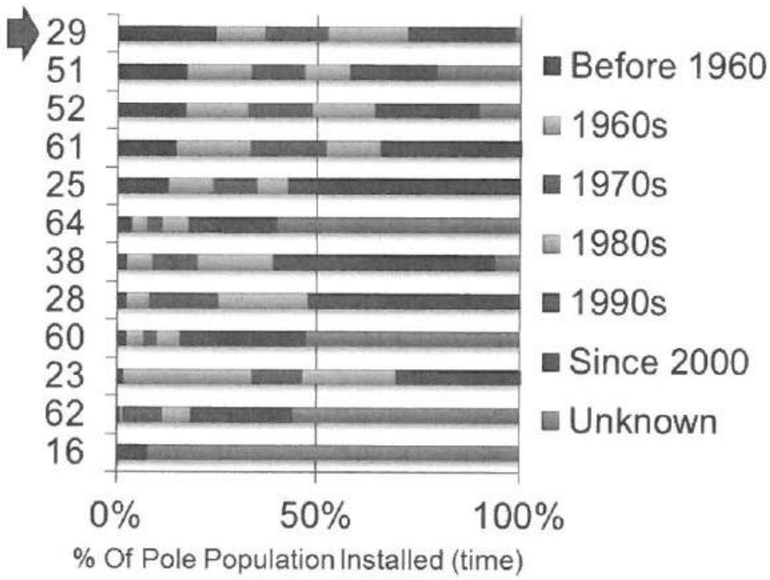
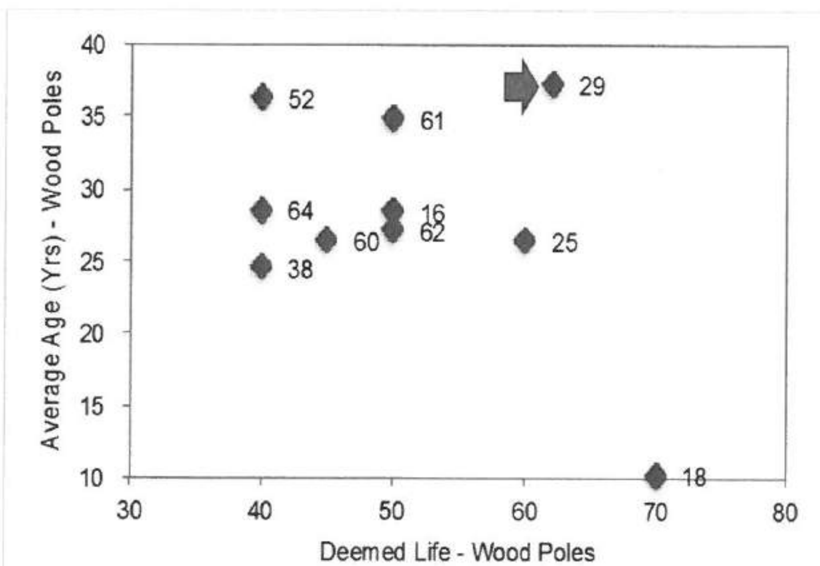


Figure 15. Average Age versus Planned End of Life

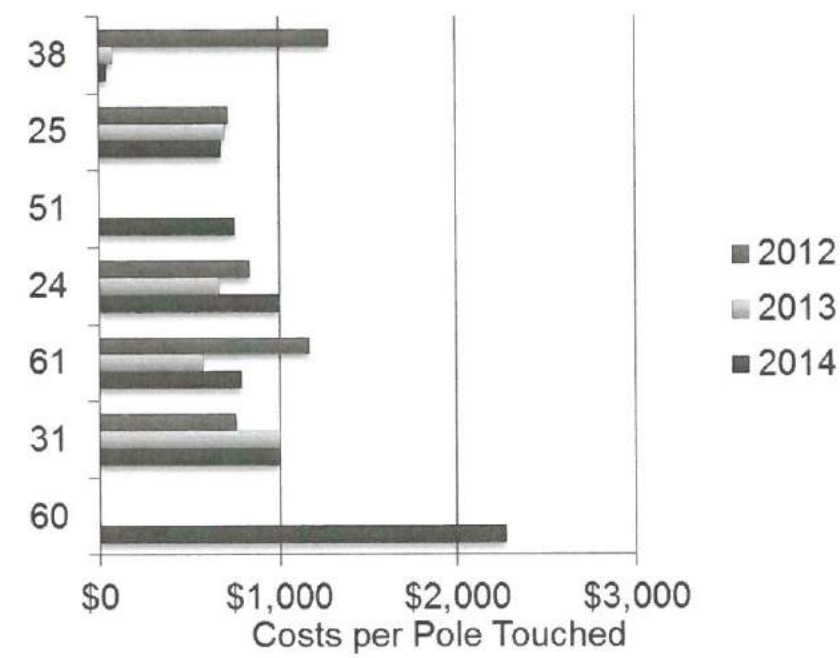


3.4 Pole Refurbishment Costs

Most North American utilities (13 of 17 in the study) have a formal distribution pole refurbishment practice in place to deal with poles that fail prematurely. Hydro One currently does not have such a refurbishment program, electing to replace poles that fail, rather than refurbish them. The fact that Hydro One has experienced a long life for its poles is one indicator of the reasonableness of this approach. At the same time, organizations with refurbishment practices in place are able to demonstrate that their lifecycle costs have improved due to the refurbishment practice.

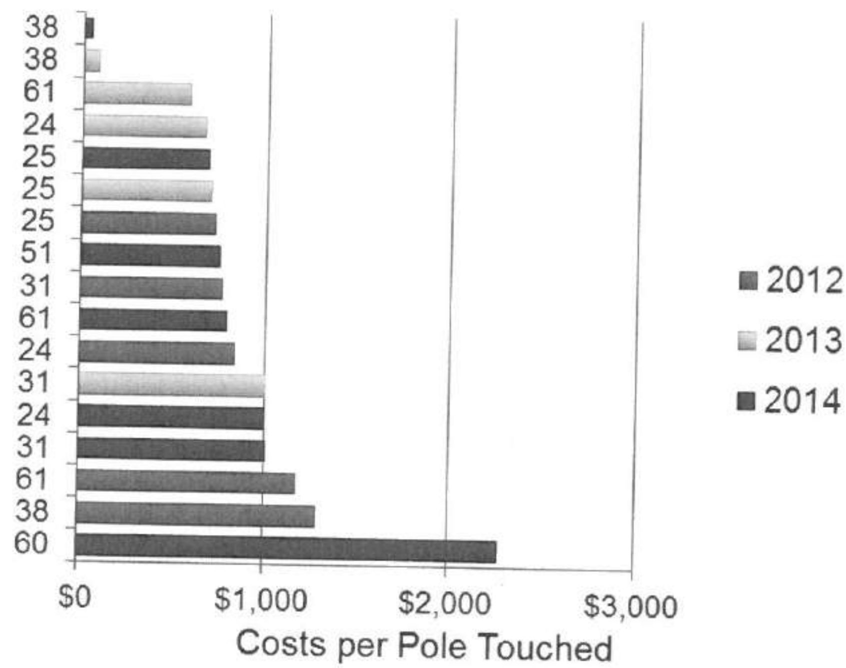
Figure 16 and Figure 17 show the unit costs for pole refurbishment for those companies who track and could report those costs. The mean cost to refurbish a pole is $947.

Figure 16. Pole Refurbishment Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles refurbished.

Figure 17. Pole Refurbishment Costs Ranked by Annual Spend



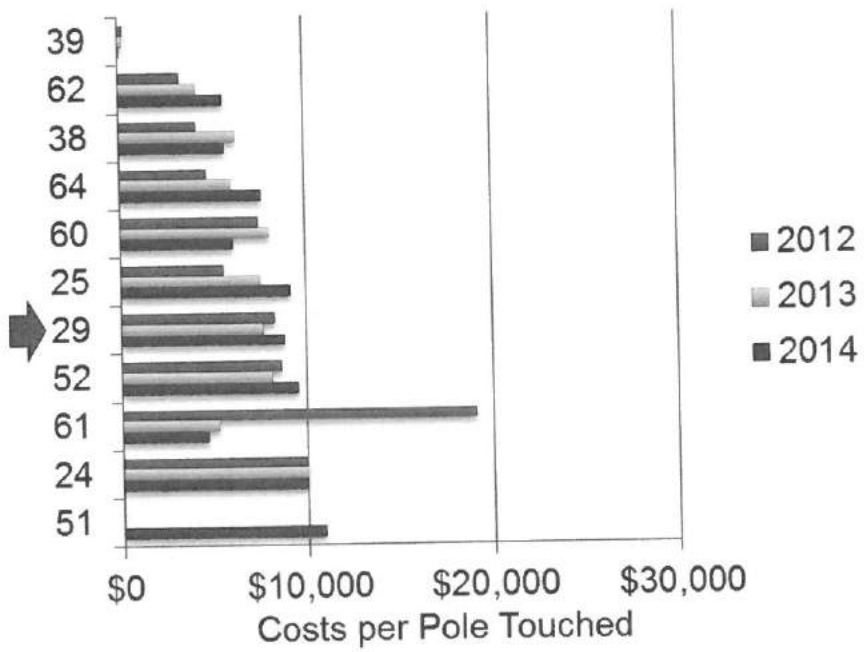
Note: In this comparison, pole touched means the total number of poles refurbished.

3.5 Pole Replacement Costs

As poles reach the end of their useful life, they must be replaced. All utilities have systematic programs for replacing those poles, with the goal of getting the longest useful life without allowing the poles to stay in service until their failure. Across the comparison group, the average cost to replace a pole is $7,105. For Hydro One, that cost is $8,266, or 16% higher than the mean.

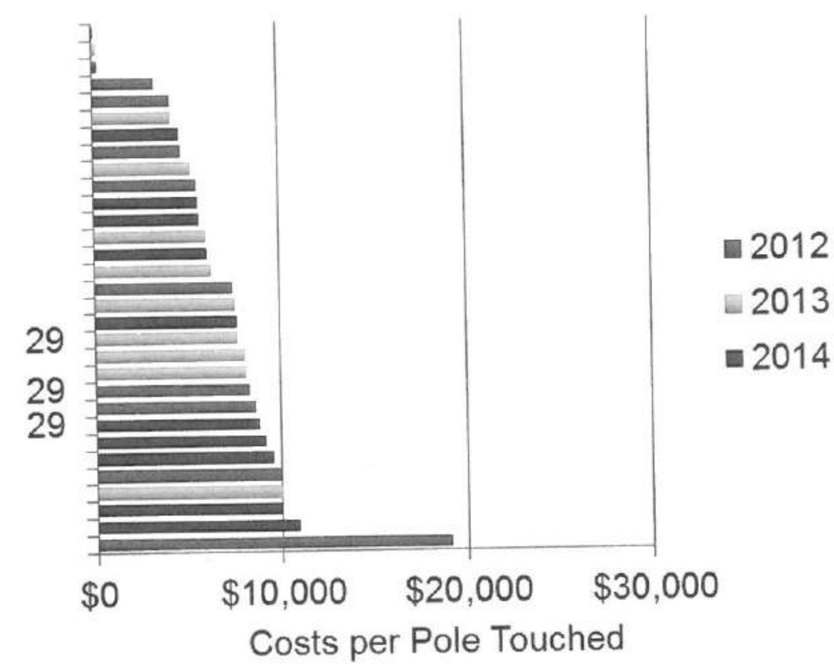
In the course of the study, a number of factors were investigated for their impact on the cost of replacing poles. This analysis revealed that these demographics had little impact on the overall results. Elements investigated include the planned life of the poles, the percent of poles installed off-road, the percent of poles installed in soft soil, the average travel time to get to poles, and average age of poles.

Figure 18. Pole Replacement Costs Grouped by Company



Note: In this comparison, pole touched means the total number of poles replaced.

Figure 19. Pole Replacement Costs Ranked by Annual Spend



Note: In this comparison, pole touched means the total number of poles replaced.

3.6 Refurbishment versus Replacement Costs

The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately 7x more expensive, where refurbishment is an option. Refurbishment is not an option in all cases. For example, it wouldn't make sense to refurbish a 50-year-old pole when its useful life is planned for 60 years. Refurbishment makes the most sense when a pole is found to be failing early in its planned life. Refurbishment has the possibility of extending the life of the pole by 20 to 40 years. In any scenario where a refurbishment can extend the life of the pole by over 20 years, then the economic benefit of refurbishment tends to be clear.

4. SUBSTATION REFURBISHMENT BENCHMARKING RESULTS

The six key findings of the station refurbishment benchmarking study are provided below.

1. Station refurbishment activities are varied within and across utilities.
2. Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities.
3. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile.
4. Navigant and First Quartile Consulting believe that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory; Hydro One has the highest percentage of single transformer substations, higher than average transformer loadings, older age profile for in-service transformers, and more rural locations.
5. Use of testing results and maintenance history records could be improved in making replace versus repair decisions for certain substation equipment.
6. Use of performance measures for tracking success of individual programs, in addition to the overall refurbishment program could be enhanced.

4.1 Cost Analysis

The analysis compared costs of substation refurbishment and rebuilding in several different ways. Since companies take different approaches to substation refurbishment, it was necessary to group the refurbishment work into several categories – full station rebuild projects, substation-centric projects, and component-based projects.

Hydro One's costs for station centric and full substation rebuild refurbishment projects fall within a reasonable range compared to comparison utilities. As with other companies, Hydro One's unit costs for individual projects vary from first quartile to fourth quartile.

Across all types of projects, Hydro One's per unit installation costs for major substation components are generally lower than those of other comparison utilities due to Hydro One' s use of less expensive, lower capacity equipment.

4.1.1 Full Substation Rebuild Projects

A limited number of companies completed a full station rebuild in the past three years. The costs associated with these projects were compared on a per-transformer bank basis and a per-MVA basis.

Figure 20. Cost per Transformer Bank Refurbished

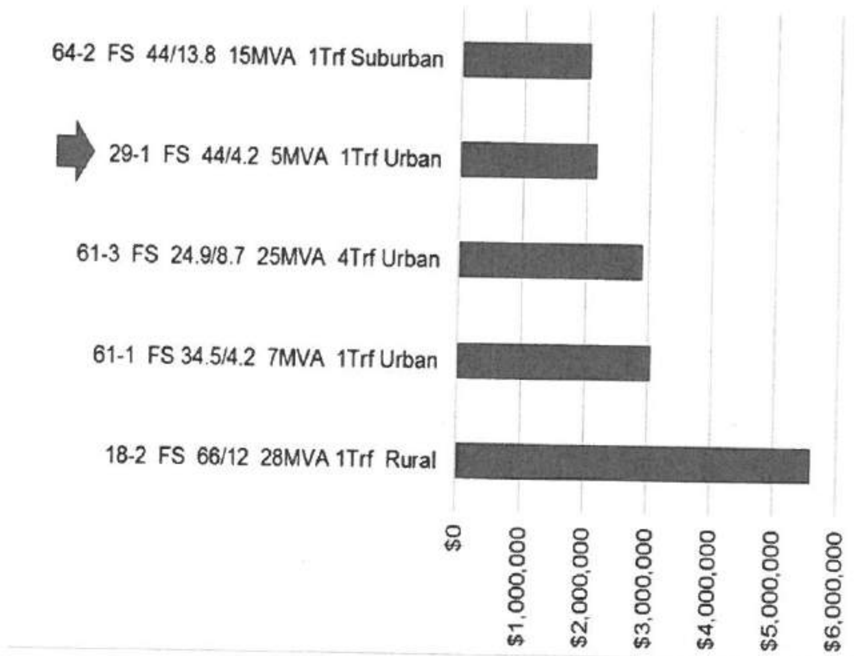
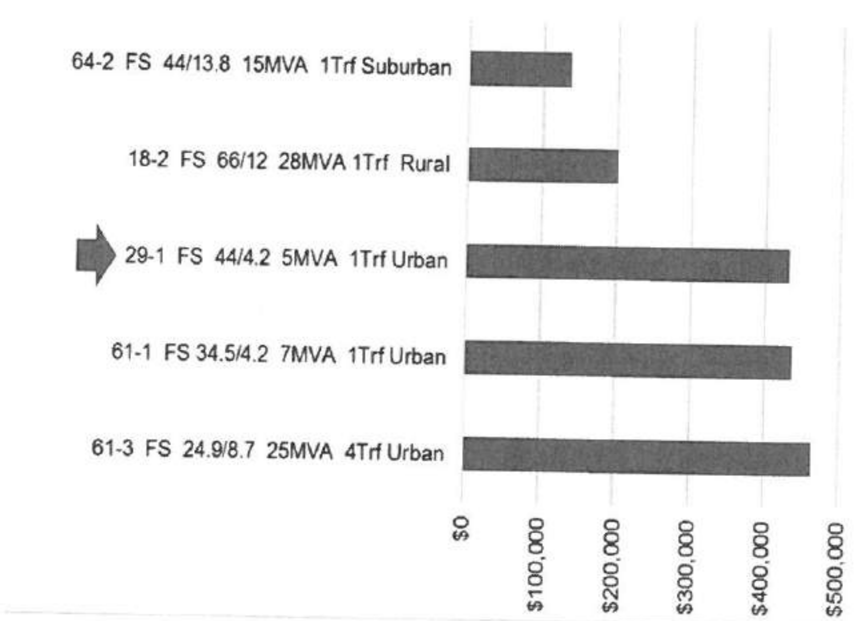


Figure 21. Cost per Substation MVA Refurbished



4.1.2 Substation-Centric Projects

A higher volume of substation-centric projects was available for analysis. As shown in Figure 22 and Figure 23, Hydro One's projects represent several of these, and they fall at different points within the comparative cost spectrum, whether measured on a per-transformer or a per-MVA basis. As before, all of the Hydro One stations in the comparison are single-transformer stations, typically at a distance from a work site.

Figure 22. Cost per Transformer Bank Refurbished for Substation-centric Projects

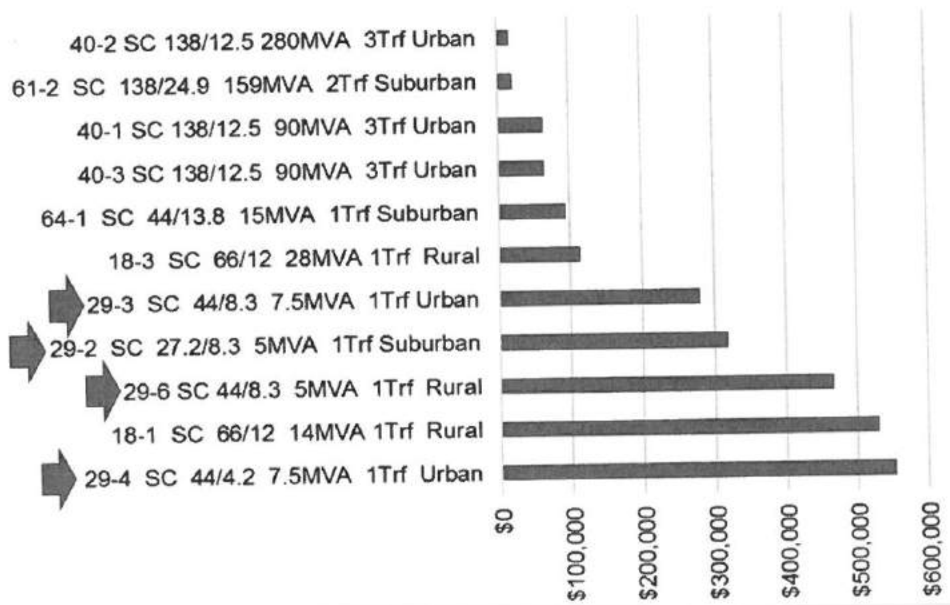
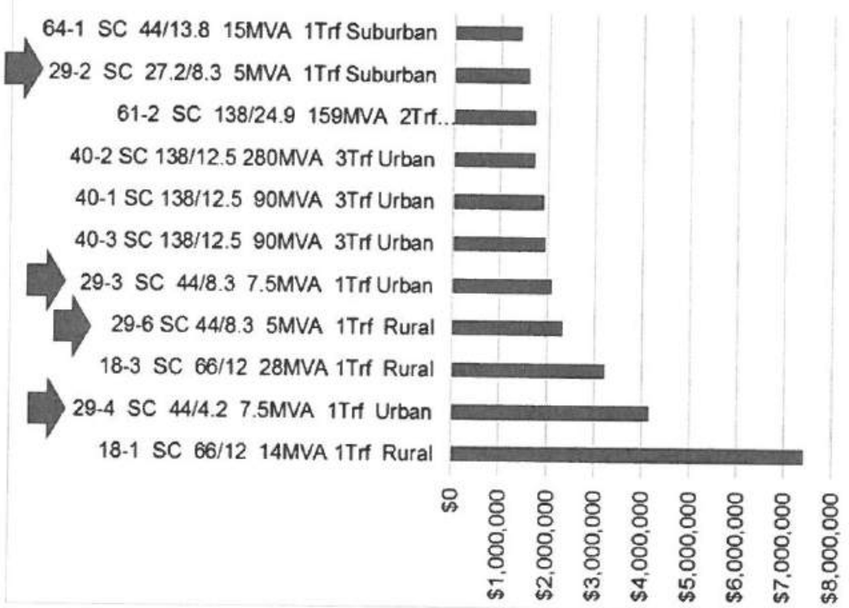


Figure 23. Cost per Substation MVA Refurbished



4.2 Operating Approach to Refurbishment

Hydro One's current emphasis on station centric and full station rebuild projects is not unique within the comparison group and is related to several demographic factors that distinguish Hydro One:

- Higher than average transformer loadings at non-coincident peak;
- An older age profile for in-service power transformers;
- Highest percentage of single transformer substations; and
- Second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile).

The demographics of the electric system, and specifically the substations, help drive the decision-making with respect to refurbishment activities. Age, condition, and planned life all influence what type of maintenance and refurbishment activities are appropriate, for individual components and for entire stations. Also important is the configuration of the system, i.e. the range of stations that have multiple transformers (or not), whether or not they are looped or structured with a radial design.

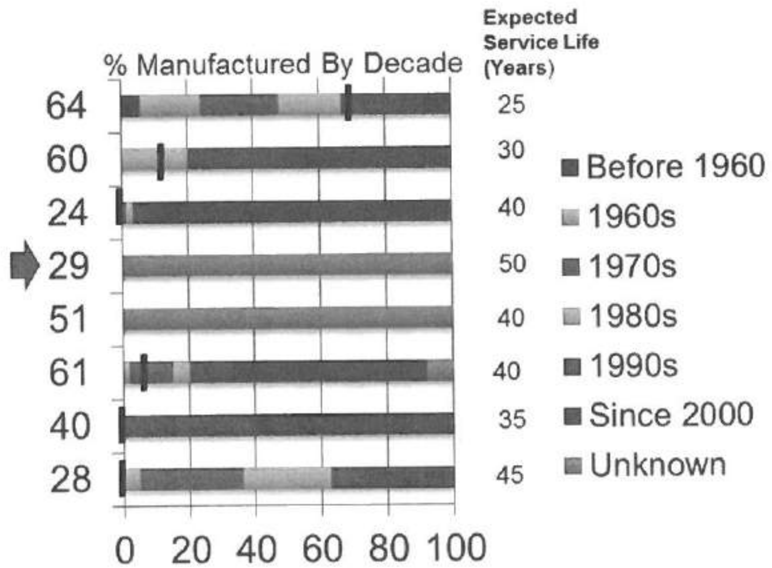
In this section, we present information about the age of the various station components, along with some information about the system configuration. While these findings aren't a measure of performance, they do have an impact on the costs and appropriate practices associated with the substation refurbishment activities.

While Hydro One's focus on station-centric and full-station refurbishment is not unique, several of the comparison companies primarily or exclusively rely on component-based refurbishment programs.

4.2.1 High Side Switching and Protection Equipment

Hydro One's expected service life for high side switching and protection equipment is higher than the comparison group average. It's actual age profile for these components is unknown.

Figure 24. Expected Service Life for High Side Switching and Protection Equipment



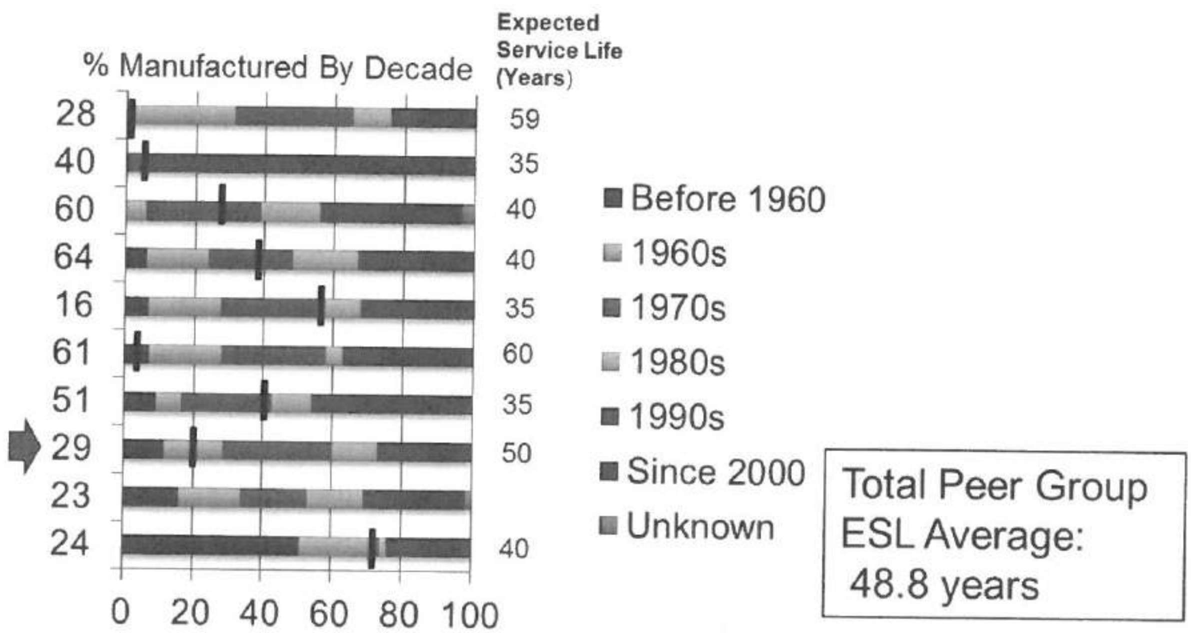
Note: The black lines indicate the approximate % of current in service components that are past their expected service life (ESL)

Total Peer Group ESL Average 42.7 years

4.2.2 Power Transformer Demographics

Hydro One's power transformer age profile ranks in the older end of the comparison group distribution. It's expected service life for power transformers is also somewhat higher than the group average, as shown in Figure 25.

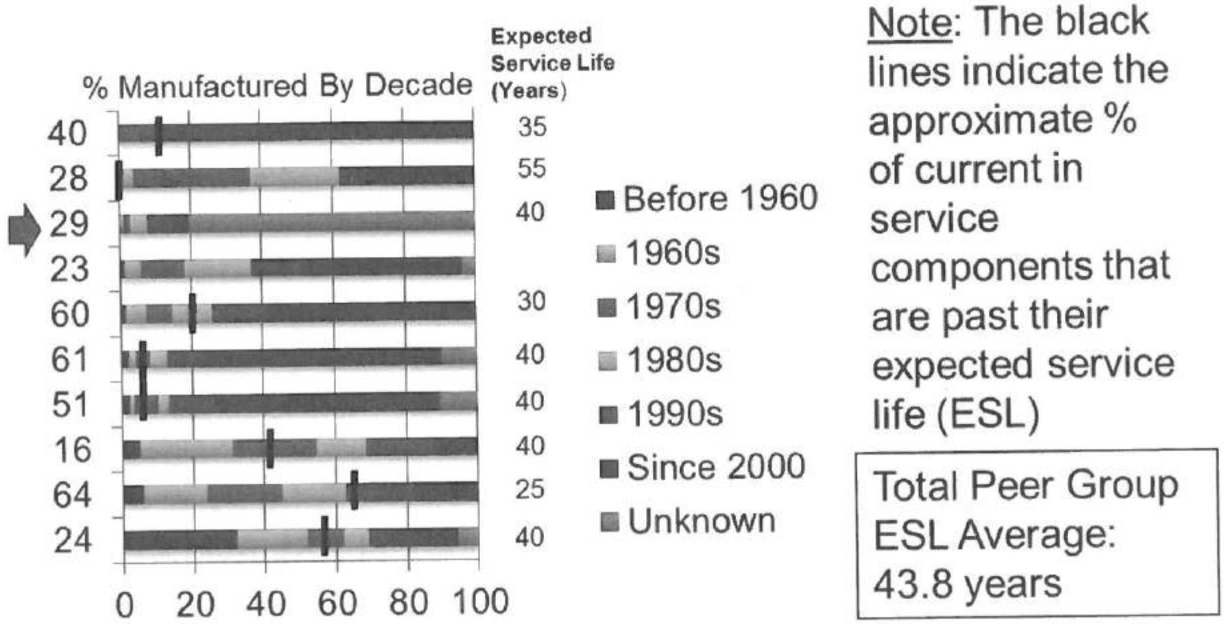
Figure 25. Expected Service Life of Power Transformers



4.2.3 Low Side Switching and Protection Equipment

Hydro One's expected service life for low side switching and protection equipment is somewhat lower than the comparison group average. Most of its actual age profile for these components is unknown.

Figure 26. Expected Service Life for Low Side Switching and Protection Equipment

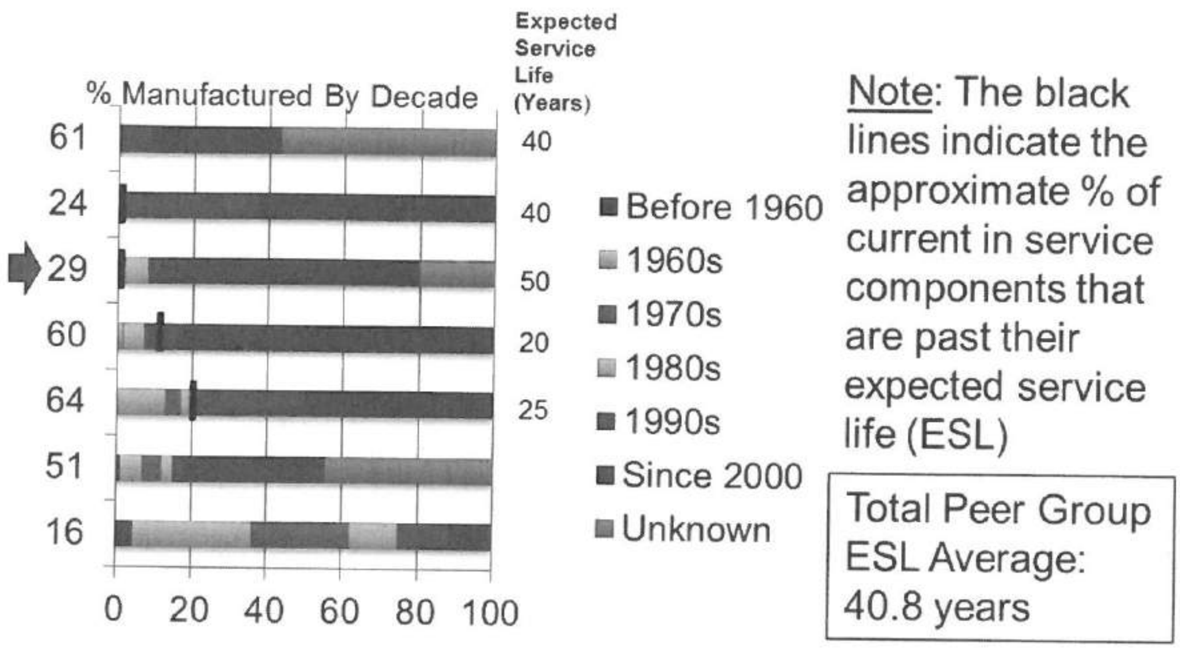


49

4.2.4 Relays and Control Wiring Demographics

Hydro One's Expected Service Life for in-service relays and control wiring is higher than the comparison group average. Most companies were not able to furnish a complete age profile for these components.

Figure 27. Expected Service Life for In-service Relays and Control Wiring



4.2.5 Substation Profiles

Hydro One has the highest percentage of single transformer substations within the comparison group. It also has a very high % of rural stations (stations serving areas that have 50 or fewer customers per square mile), meaning there are many stations with single transformers in remote locations.

Figure 28. Percent of Substations by Number of Power Transformers

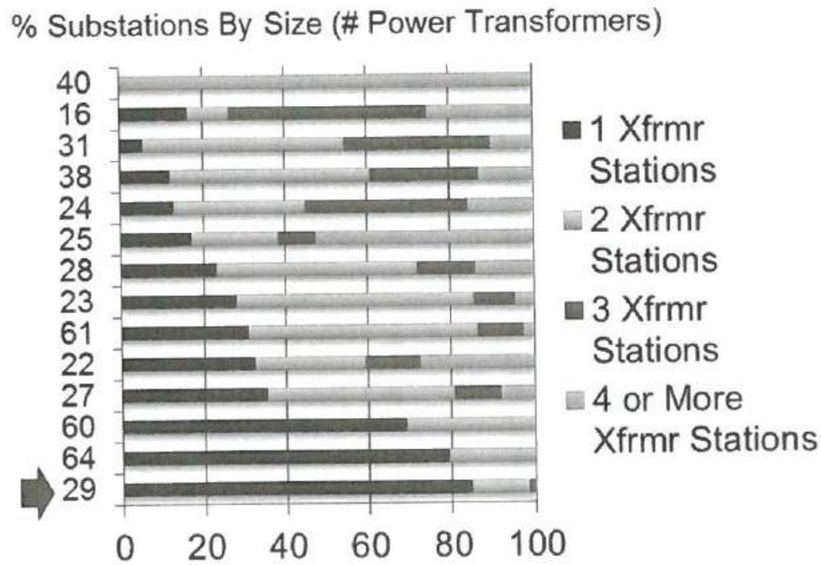
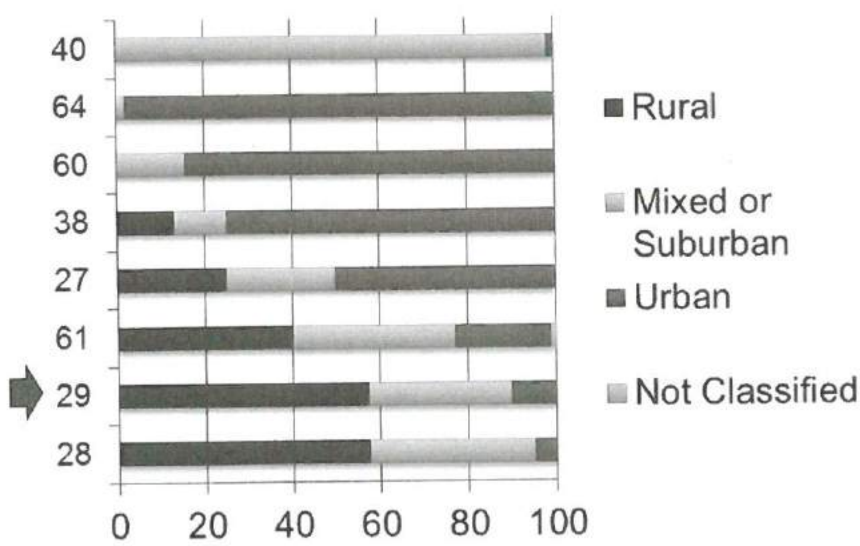


Figure 29. Percentage of Substations by Area: Rural, Urban and Mixed



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Scorecard - Hydro One Networks Inc.

9/24/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		95.70%	97.40%	97.40%	97.50%	98.60%	up	90.00%	
		Scheduled Appointments Met On Time		98.60%	98.40%	99.30%	98.50%	99.50%	up	90.00%	
		Telephone Calls Answered On Time		83.40%	63.90%	69.60%	76.40%	74.20%	up	65.00%	
	Customer Satisfaction	First Contact Resolution			78.30%	79%	82%	82			
		Billing Accuracy				94.63%	98.59%	99.04%		98.00%	
		Customer Satisfaction Survey Results			87%	85%	85%	84			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness					81.00%	81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	NI	C	NI	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	6	7	4	5	11	flat		4
			Rate per 10, 100, 1000 km of line	0.051	0.059	0.033	0.042	0.091	flat		0.035
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		6.98	6.88	7.49	7.65	7.83	down		10.31
		Average Number of Times that Power to a Customer is Interrupted [2]		2.61	2.49	2.70	2.63	2.47	down		2.93
	Asset Management	Distribution System Plan Implementation Progress			Under Review	97%	116%	105			
	Cost Control	Efficiency Assessment		5	5	5	5	4			
		Total Cost per Customer [3]		$1,041	$1,046	$1,069	$983	$987			
		Total Cost per Km of Line [3]		$10,741	$10,682	$10,916	$10,198	$10,551			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]					17.27%	42.50%			1,220.69 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		99.39%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time			99.71%	100.00%	99.78%	99.22%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.99	1.00	0.99	0.97	0.80			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.30	1.35	1.31	1.19	1.46			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.66%	9.30%	9.19%			
			Achieved	8.72%	8.00%	6.26%	8.77%	8.41%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend: 5-year trend: up, down, flat
Current year: target met, target not met

53

55

4

2017 AACE® INTERNATIONAL TECHNICAL PAPER

RISK.2516

Variability in Accuracy Ranges: A Case Study in the Canadian Power Transmission Industry

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Abstract—This paper presents a case study of the variability in accuracy ranges for cost estimates in the Canadian overhead power transmission industry. The study sought to improve the participant's understanding of risks and estimate accuracy for their major overhead power transmission projects. The study team also sought to verify the theoretical accuracy curves identified in the AACE® International Recommended Practice (RP) 18R-97: "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for The Process Industries". The study team collected and analyzed actual and phased estimate cost data from 39 projects with actual costs from 2 million to 655 million (2016$CAN) completed from 2007 to 2016. Greenfield and brownfield overhead transmission projects from across Canada were included. This study compares the range bandwidth (uncertainty) as stipulated in AACE® RP 18R-97 with the actuals from this study. The accuracy ranges and the project's under or over estimation of contingency is compared with published data from other industry studies.

Table of Contents

Introduction/Background

Accuracy is a measure of how a cost estimate differs from the final actual outcome. Risk analysis provides forecasts of how the final actual outcome may differ from the estimate (such as a base estimate or an amount approved for expenditure). Historical analysis helps us to understand the variability of accuracy and to improve our risk analysis practice [1]. This study is such an historical analysis.

Empirical estimate accuracy data has been researched for over 50 years [2]. In particular, the accuracy of process industry project estimates (e.g., oil and gas, chemical, mining, etc.) has been well documented [3]. Other studies have highlighted industry bias and misperceptions of the reality of estimate accuracy [4]. However, there has been a relative void in accuracy studies for overhead power transmission projects. One example study for the power industry included transmission projects but barely reported on their experience [5]. Most cost studies are of absolute costs (e.g., $/kW), not estimate accuracy. This study of the accuracy of estimates for the Canadian power industry will help fill a gap in our understanding of the power transmission element of the electric power industry.

One catalyst, and point of comparison, for this study was the development by the Construction Industry Institute® (CII) of a Project Definition Rating Index (PDRI) for "Infrastructure" projects in 2011 [6]. The CII report included some limited historical accuracy data for cost and schedule but only a small number of the projects were power transmission scope. CII defined infrastructure as providing "transportation, transmission, distribution, collection or other capabilities" that usually impact multiple jurisdictions and stakeholders across a wide area. CII characterized infrastructure as scope including "nodes and vectors"; in that respect, this study covers the power "vector" aspect; i.e.., transmission lines as opposed to generation and substation "nodes". For this paper's study, it was hypothesized that vector projects which include unique land, right-of-way and permitting issues and risks may have different estimate accuracy characteristics than nodal projects.

In respect to the nodes (e.g., generation and substations), this study is partly an extension of a 2014 study on hydropower generation projects by the same group that sponsored this study [7]; this study's analytic methods were essentially the same.

In addition, this study was needed to help verify the applicability of the theoretical accuracy depiction presented in Figure 1 of the AACE® Recommended Practice 18R-97 "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries" [8]. The questions in regard to that RP were "does Figure 1 in RP 18R-97 reflect real accuracy ranges?" and if not, "how can we assure that this depiction does not feed bias in stakeholder expectations?" (Figure 1 from RP 18R-97 is reproduced below):

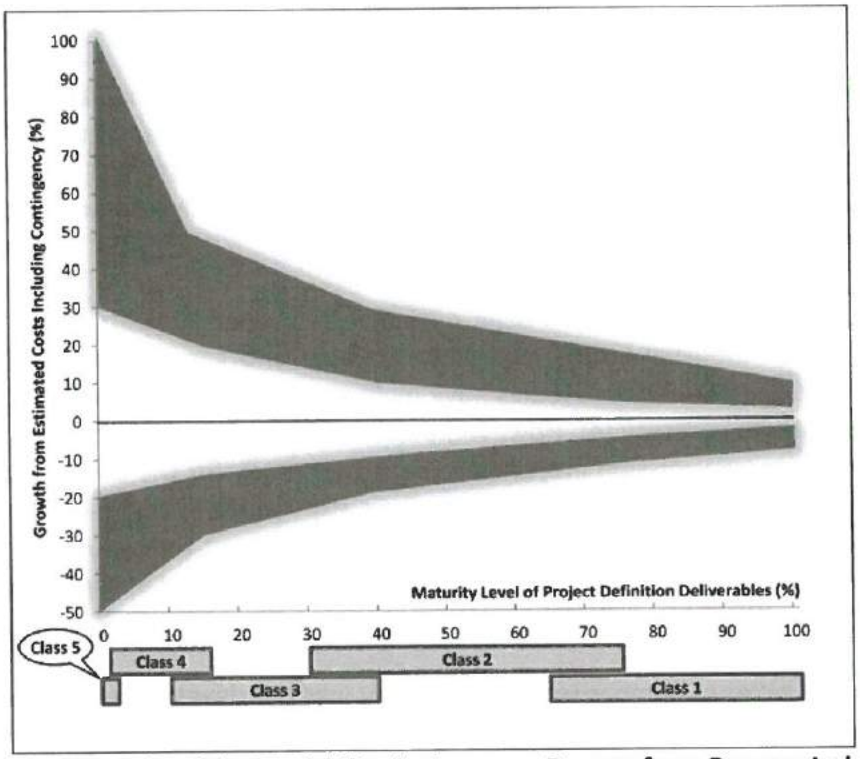

Figure 1 – Example of the Variability in Accuracy Ranges for a Process Industry Estimate **(Figure 1 from AACE International RP 18R-97; copied with permission)**

Background on the Study

Since the publication of the CII PDRI-Infrastructure, the AACE® Technical Board has been considering a Recommended Practice (RP) for the classification of infrastructure industry estimates. An initial RP goal was to document the defining scope deliverables and their expected status to support project estimates of each Class. Optimally, the RP would be backed up by industry empirical data. In anticipation of this, and to address its own interests, the Canadian study team developed its own transmission scope deliverable list and status worksheet and performed an empirical analysis. Also, the Canadian study team (the membership has changed slightly) did a similar study of hydropower generation projects in 2014 [7]; this study would add to their cost knowledge of their asset base.

The Canadian study team collected estimated and actual project capital cost data from 39 recent projects with actual costs from $2 million to $655 million (average $61M in 2016 $CAN) completed from 2007 to 2016. A goal of the study was to assess the accuracy versus level of scope definition, so for each project, estimate data from each scope development phase was captured, resulting in data on 79 estimates. Only 25 of the projects had records of Class 5 (conceptual) estimate data.

The project scopes included overhead AC and HVDC transmissions lines (no substations) from 25 to 500kV, with 1 to 3 circuits on wood or steel support structures. The routes were new or existing from 0.4 to 340km in length (average 48km) in 5 Canadian provinces. Most of the projects did not require new regulatory approval (i.e., line was often covered under a wider regulatory umbrella); however, the larger the project, the more likely approval was required. To minimize bias, the dataset represented all the recent major project data available to the participants regardless of whether the project cost outcome met company objectives.

Analysis Approach

The primary analytical methods used were descriptive statistics. The accuracy metric described by the statistics and the dependent variable of regression was the ratio of "base estimate/actual costs". "Base estimates" of each Class exclude contingency, escalation and management reserves. This was used because the team wanted to understand how actual costs differed from the base so that they could improve future predictions of this difference (i.e., forecast the contingency required). The study also examined schedule duration estimate accuracy which is not included in this paper.

The estimate/actual cost ratio format was used because sample data of this metric tends to be normally distributed and hence amenable to multiple linear regression analysis. As will be discussed later, the more commonly considered actual/estimate (inverse of estimate/actual) tends to be biased to the high side which can make regression analysis problematic.

The independent variables studied (estimate/actual being the dependent variable) included:

- Scope definition upon which estimate was based (i.e., AACE® Class 3, 4 or 5)
- Province/Company
- Proximity to populated areas
- Cost/Schedule Strategy (i.e., cost or schedule driven)
- Terrain/Site Conditions/Weather
- New Technology or Scale
- System Complexity
- Execution Complexity
- Primary Project Type (e.g., greenfield, revamp, etc.)
- Primary Construction Contract Type
- Owner PM System Maturity
- Aboriginal Stakeholder Engagement / Involvement
- Environmental Sensitivity of ROW

Also, the cost content of each project in terms of percent of cost for procurement, construction, and so on was also captured. To collect the data, the team developed a form that captured the following:

- General project characteristics
- High level "base" cost estimate breakdowns at each AACE® Class plus contingency and escalation cost estimates for each
- Actual final cost
- Key planned and actual schedule milestones
- Scope change and risk event information

The actual cost data was normalized to the year of the respective estimate using the mid-point of spending approach (actual project cash flows were not available) [9]. The normalization price index used was derived from the Statistics Canada index for the sell price of non-residential construction projects. Also, cost changes due to business scope change were adjusted out (costs resulting from a change to a basic premise of the estimate such as transmission line voltage, capacity, etc.). None of the projects were observed to have experienced a catastrophic risk event.

The primary variable (risk driver) of interest was the level of scope definition upon which the estimate was based. Not all projects had data for estimates of each AACE® Class as can be seen in the following number of valid observations:

- Class 3: 29 (10 of the 39 were funded based on a Class 4 estimate)
- Class 4: 25 (10 of these were the funding estimate)
- Class 5: 25

This sample size was considered adequate to gain useful insight as to the relationship of accuracy and Class, but not enough to gain deep understanding of the impact on accuracy of any but the most dominant of the other independent variables.

Findings for Accuracy Range by Class: Descriptive Statistics

Table 1 shows the dataset statistics for accuracy. Figure 2 depicts the same data fitted to lognormal distributions. The probability values ("p-value" is the level of confidence expressed as a percentage of values that will be less than that shown) in the table are calculated using the Excel® "Norminv" function applied to the base estimate/actual data, and then converted to the traditional actual/base estimate ratio format (i.e., >1 means the actual cost was more than the base estimate.) This method of inferring the population distribution from a sample is consistent with the method described in AACE® RP 42R-08 (Risk Analysis and Contingency Determination using Parametric Estimating) and supported by process industry research that indicates that estimate/actual data (as opposed to its inverse of actual/estimate) is more or less normally distributed [1].

As an example of how to interpret this, if the ratio for Class 4 at p50 is 1.24, that indicates that 24% contingency would be needed to achieve a 50 percent confidence of underrunning. Note the high side skewing (e.g. the Class 4 p90 of 2.34 is much further from the mean than the p10 value of 0.84). Recall that these values exclude escalation and business scope change.

Actual/Base Estimate	Class 3	Class 4	Class 5
number of observations	*29*	*25*	*25*
p90	1.64	2.34	2.66
p50	1.08	1.24	1.38
p10	0.81	0.84	0.93

Table 1 – Dataset Cost Estimate Accuracy Metrics (Actual/Base Estimate)

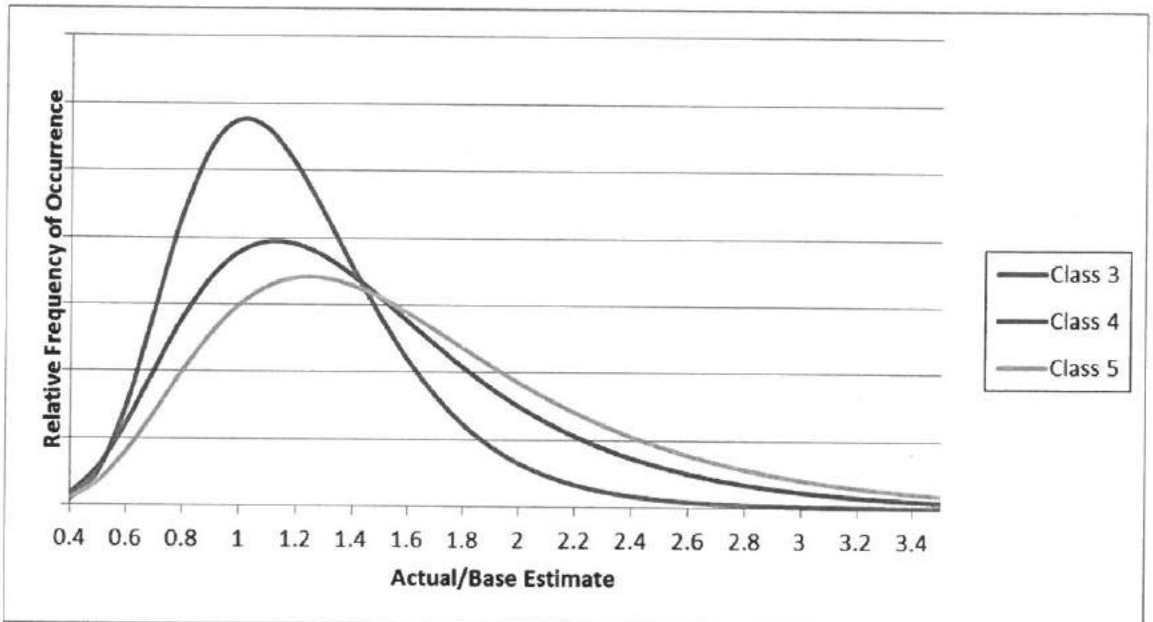

Figure 2 – Dataset Actual/Base Estimate Metrics Fitted to Lognormal Distributions

Findings on Effect of Project Size

The project size in this study's dataset sample was not evenly distributed. There was a group of 20 projects of <=$20 million actual cost (average $8 million) and a group of 19 projects of >$20 million actual cost (average $118 million) (all $2016 $CAN). Industry research indicates that there is a dichotomy between how small versus large projects are managed and estimated [10]. Small projects tend to be managed as a portfolio with project team members having responsibility for multiple projects using less disciplined management procedures. Large projects usually have dedicated teams and more disciplined procedures. The focus of small project funding tends to be on overall portfolio budget predictability which translates to a bias towards over-estimation, while large projects focus more on individual project cost effectiveness which translates to a bias toward under-estimation. These industry findings are consistent with this study's findings.

For example, in Table 2, the p50 value for the Class 3 estimates of small projects (<=$20M) is 1.01 which means the average project actual cost was essentially equal to the average base estimate excluding contingency; i.e., the base estimates appear to have been conservatively biased such that no contingency was needed on average. On the other hand, the large projects (>$20M) had much greater p90 values indicating not only was base estimate bias towards under-estimation, but the project complexity (and longer durations of 35 months versus 27 months from start of execution phase to in-service date) appears to have resulted in greater risk. In particular, several of the largest projects required specific regulatory approval.

Actual/Base Estimate	Class 3		Class 4		Class 5	
	<=20M	>20M	<=20M	>20M	<=20M	>20M
p90	1.32	1.96	1.98	3.79	2.32	3.18
p50	1.01	1.15	1.19	1.37	1.40	1.36
p10	0.82	0.81	0.85	0.83	1.00	0.87

Table 2 – Dataset Cost Estimate Accuracy (Act/Base Est) by Project Actual Cost Range

Comparison of Findings to Other Studies and AACE® RP18R-97

Statistically speaking, considering sample sizes and data quality, this study's accuracy ranges are roughly comparable to those reported for the process industries [3 and 4] as well as infrastructure projects in the CII PDRI-Infrastructure study [6]. However, this study's Class 4 and 5 cost growth ranges were more similar to each other than they were for process plant projects. One hypothesis is that process plant projects usually have outside battery limits and offsite scope elements (i.e., significant scope elements supporting but not part of the process production units) with poor early scope definition causing greater Class 5 underestimates for process plants. Another explanation is that transmission projects are less technically complex; i.e., the main uncertainty is around routing which is similarly defined at Class 4 and 5. Also, the p10 values (significant underruns) of the transmission projects, many of which are fairly small, indicate a bit more bias towards overestimation. Table 3 summarizes the results of these studies.

It was assumed that funding estimates in the Hollmann study [4] were based on scope definition of about Class 4 because general industry front-end planning is assumed to be less defined on average than at the companies in this study and at the clientele of Independent Project Analysis, Inc. (IPA). However, the estimates in the CII study [6] were assumed based on Class 3 estimates given their average PDRI scope of <200 (on a scale of 70 to 1,000 with 70 being best and 200 or less being the CII recommended target level for sanction).

Note that this study's values were adjusted downward from Table 1 to reflect the accuracy relative to the estimate including contingency (i.e., the funded amount) which is typical of the data shown in most published studies. The contingencies added to this study's Class 3, 4 and 5 base estimates were 10%, 12% and 15% respectively which correspond to typical contingencies applied at the time.

This Study	**Class 3**	**Class 4**	**Class 5**
p90	54%	122%	151%
p50	-2%	12%	23%
p10	-29%	-28%	-22%
IPA Inc., Process Industry [3]; p10/p90 approximated from histogram illustration			
p90	40%	70%	200%
p50	1%	5%	38%
p10	-15%	-15%	-15%
Hollmann, Process Industry [4] average of meta-analysis			
p90		70%	
p50		21%	
p10		-9%	
CII Infrastructure PDRI [6] data from Figure 6.6 (mean PDRI <200)			
p90 (assuming normal)	30%		
Mean	6%		
p10 (assuming normal)	-11%		

Table 3 – Comparison of Accuracy Studies (% Overrun of Estimate Incl. Contingency)

When comparing results in respect to RP 18R-97, one must consider two points of comparison. The first is the bandwidth or span of the range (i.e., p90 minus p10.) The other is the absolute value of a high or low range. Figure 3 shows this study's results superimposed on the RP 18R-97 Figure 1. This study's range spans are somewhat wider (more uncertain) than the worst case spans in the RP. For example, the worst case span for Class 5 in the RP is 150% (100 – <50>) while the span for Class 5 in this study is 173% (151 – <22>.) The high and low absolute range values indicate contingency under-estimation bias (albeit less bias than for hydropower generation projects [7]). Even if only the study's small project range values had been plotted in Figure 3, the Class 3 range at best would be similar to the worst case span of RP 18R-97 (i.e., the RP Figure 1 is optimistic).

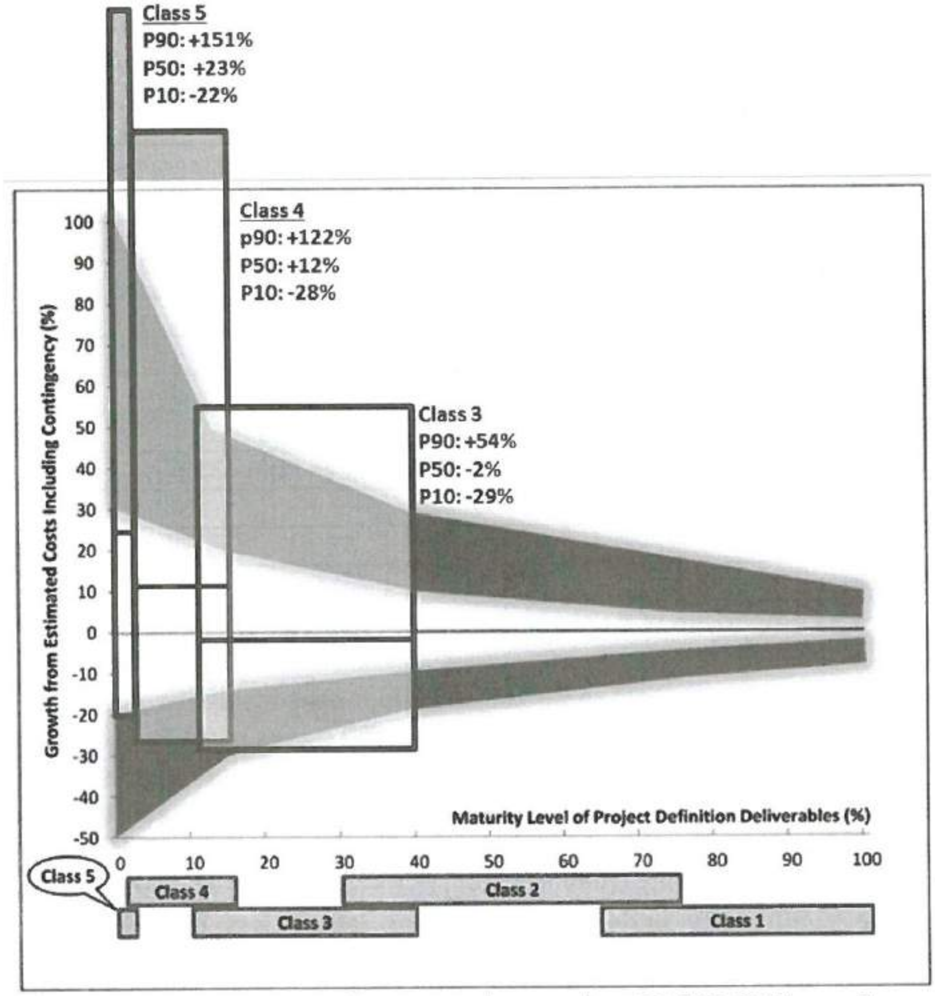

Figure 3 – Study Accuracy Findings Superimposed on RP 18R-97 Figure 1

Comparison of Contingency Estimates to Actual Cost Growth

The projects in this study allowed only 10 to 15% contingency on average, even for Class 5 estimates. These contingencies appear to reflect a strong industry optimism (under-estimation) bias for large projects, particularly for early estimates. Contingencies (or combinations of contingency and management reserve) of 8, 24 and 38% at p50, excluding business scope change and escalation, are suggested by this study for Class 3, 4 and 5 estimates respectively for transmission projects of average size and risks. However, there is a dichotomy between small and large projects. For small projects (<$20M), the base estimates were more conservatively estimated at Class 3 and 4 such that a contingencies of 0, 20 and 40% at p50 would have sufficed. However, the high p90 values of large projects points to the need for more rigorous risk management to identify and mitigate their greater potential risks.

If these empirically-valid contingencies, allowing for size bias, had been included in the study projects, their actual range outcome would look similar to but wider than the worst case of RP 18R-97 Figure 1. The authors are not recommending that these or any other contingency values be assigned arbitrarily; contingency should always be based on risk analyses. However, if a company's risk analyses regularly result in 10 to 15% contingency and narrow ranges with less than ideal scope definition, it is likely that risks and their impacts are not being identified or quantified properly and/or optimism bias is controlling.

Regression Analysis of Other Risk Drivers

The study team has also modeled the impacts of systemic risks other than the level of scope definition and project size. To do this, the data from only the Class 3 estimates was examined (Class 3 being the basis for full funding decisions and hence of utmost importance to the business stakeholders). Using multiple linear regression, each independent variable (risk driver) was tested alone and in various combinations. While the findings from the modeling are confidential, a conclusion of the modeling that can be shared was that the level of scope definition is the predominant systemic risk driver for cost growth.

Conclusions

This study of the variability in accuracy ranges for cost estimates in the Canadian power transmission industry suggests that the actual cost uncertainty is a bit greater than the worst case theoretical depiction of accuracy for the process industries in Figure 1 of AACE® RP 18R-97. The study indicates that risks are much greater than being estimated; contingencies of 8, 24 and 38% percent were indicated for Class 3, 4 and 5 estimates respectively on average. The study also shows that the contingency and reserves estimated were lower than what were required. The study also shows that small projects (<=$20M) appear to have a base estimate bias towards over-estimation at Class 3; however, the contingencies are still underestimated at Class 4 and 5. Finally, large projects (>$20M) have greater risk on the high side (p90) indicating a need for strong risk management. Overall, and in respect to size variations, the Canadian power transmission industry experience is similar to that of other process industry projects, as well as of infrastructure projects studied by CII.

Using the data from the study, the participants have developed a simple parametric risk analysis tool for systemic risks in which the level of scope definition is the dominant risk driver. This emphasizes the importance of doing disciplined Class 3 scope definition prior to full funds authorization if cost predictability is a goal. The Canadian study team will recommend that the AACE® Cost Estimating Technical Committee consider this study's findings in development of an RP for classification of estimates in the infrastructure industries. The conclusions are likely applicable to other "vector" oriented infrastructure projects such as pipelines and roads.

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70

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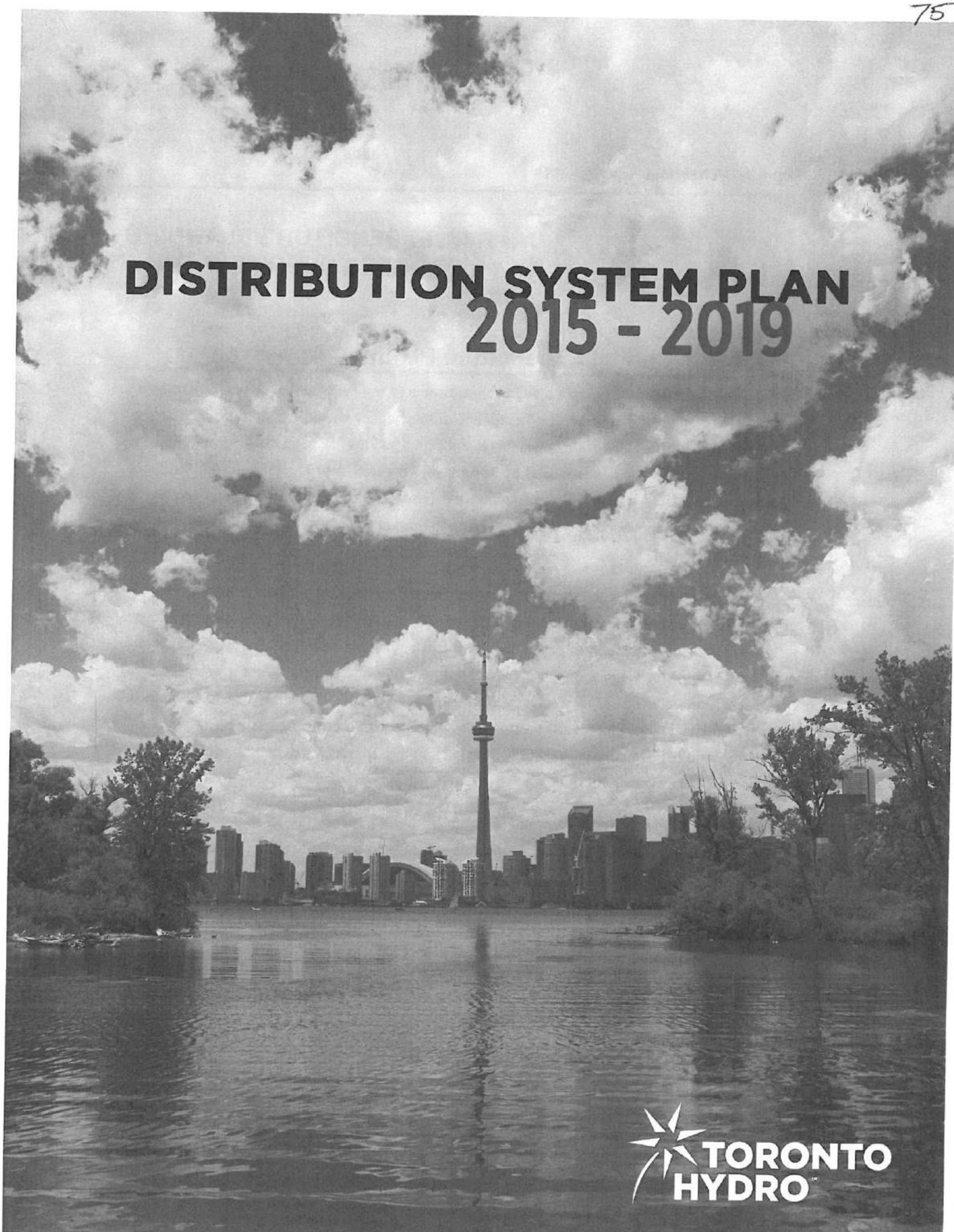
DISTRIBUTION SYSTEM PLAN 2015 - 2019



TORONTO HYDRO

E2 CAPITAL EXPENDITURE PLANNING PROCESS OVERVIEW

E2.1 Capital Expenditure Planning Approach

The reliability of Toronto Hydro's distribution system is facing increasing pressure due to a large amount of aging and deteriorating infrastructure assets, legacy equipment, and obsolete devices. Should these assets be allowed to fail, there would be a serious risk of increases in the frequency and duration of outages experienced by Toronto Hydro customers. The utility's plant also faces critical system-level issues that go "beyond the asset"[1], such as continued load growth with limited capacity, contingency issues concerning the radial downtown system, and safety issues that pose potential risks to field workers and the general public.

Toronto Hydro executed its Long-Term System Review process, as defined in Section D3.1.1.2, as part of the 2015-2019 capital expenditure plan in order to (i) derive a proactive capital investment approach that addresses all known challenges and advances the system toward an optimal balance between required capital investment and aggregate risk costs associated with asset failure (referred to as a "steady state"), (ii) evaluate various strategies to execute this approach in a manner that is responsive to customer's price sensitivity while being practical to execute, and (iii) compare the reliability outcomes of this approach against the "do nothing"/"run to fail" approach.

The "steady state", as first discussed in Section D3.1.1.2(i), reflects an optimal balance between capital investments required for the distribution system and aggregate risk costs associated with the broader asset population. In order to achieve a steady state, assets across the distribution system must be evaluated and intervened upon based upon their optimal intervention timing results – also known as the economic end-of-life criteria.

The calculation of the economic end-of-life for an individual asset is further illustrated in Figure 1, where the increasing annualized risk cost (in orange) and the decreasing annualized capital cost

[1] "Beyond the asset" refers to issues and corresponding interventions that do not necessarily relate to asset replacements. Issues that go "beyond the asset" are not necessarily due to asset failure or may refer to functionally obsolete infrastructure where the problem doesn't relate to a single asset or asset class but rather the infrastructure as a whole, including design, location, etc. Examples include safety, contingency, capacity, load growth, security-of-supply issues.

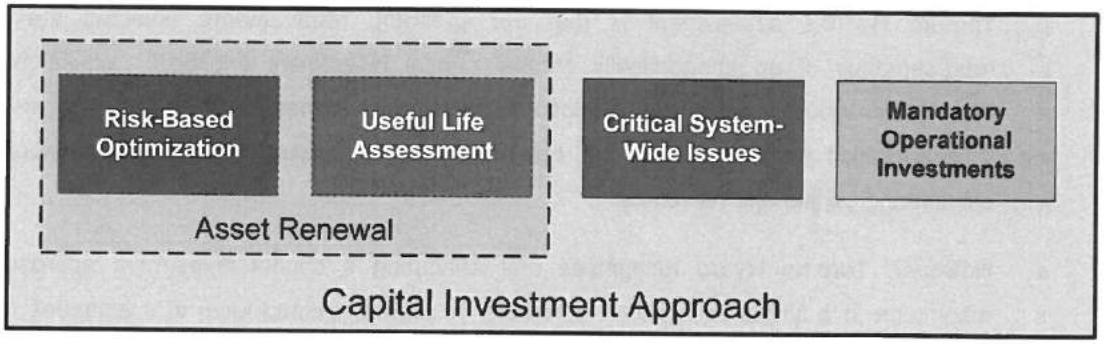


FIGURE 3: CAPITAL INVESTMENT APPROACH (2015-2019)

(a) **Asset Renewal:** To achieve steady state, in-kind replacement must be performed for those assets reaching or exceeding their economic end-of-life criteria. The Feeder Investment Model can be applied as to identify the economic end-of-life criteria and investment timing for all evaluated assets as per a risk-based optimization approach. For those asset classes not evaluated by the FIM, asset investment timing was determined based upon the assets' remaining useful life.

(b) **Critical System-Wide Issues:** This area of investment includes those broader investments of the utmost urgency, designed to target issues that go "beyond the asset", such as load growth, capacity and contingency constraints, operational flexibility and accessibility, safety and security of supply issues.

(c) **Mandatory Operational Investments:** This area of investment includes those necessary and mandatory day-to-day investments that support the 24/7 operations of Toronto Hydro, including customer-service requests, mandated service obligations, capital and maintenance support and non-system physical plant investments associated with Information Technology, Fleet and Facilities.

The spending requirements produced by this capital investment approach, illustrated in Figure 4, reveal a substantial investment backlog of approximately $2.56 billion that would optimally be /C spent in 2015, followed by approximately $1.55 billion in investment from 2016 through 2019 (in aggregate). The backlog is comprised predominantly of assets that are past their economic end-of-life and end-of-useful life respectively, as well as critical issues that must be urgently addressed. This backlog exposes Toronto Hydro's distribution system to immediate risks.

Toronto Hydro's assessment is that the spending requirements reflected are ultimately representative of an economically optimal capital investment approach: execution of these investments would mitigate this backlog and allow for an immediate achievement of steady state. This approach would minimize the operating costs to which customers are exposed when considering capital and risk costs.

However, Toronto Hydro recognizes that executing a capital investment approach of this magnitude in a single year would constitute an unprecedented level of investment, and would result in large step-increases in rates. Moreover, the utility could not reasonably expect to execute this magnitude of investment in a single year considering current system constraints and available resources.

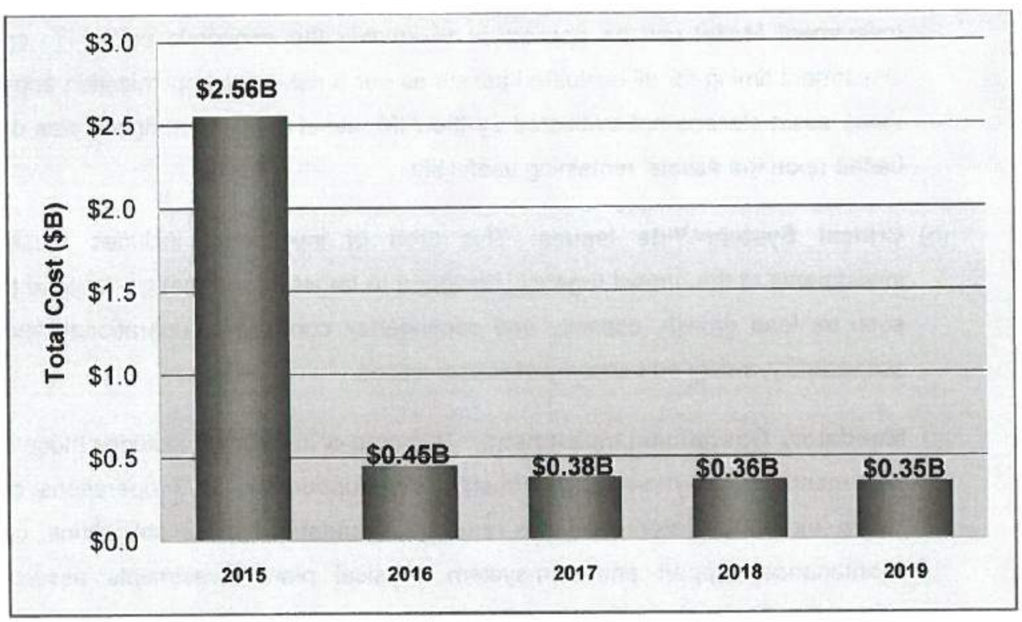


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FIGURE 4: ECONOMICALLY OPTIMAL CAPITAL INVESTMENT APPROACH (2015-2019)

Recognizing the infeasibility of completing this work in a single year, Toronto Hydro considered two alternative timelines in which to carry out this work: an "accelerated" strategy as well as the proposed "paced" strategy. The accelerated strategy would allow for the backlog of investments to be managed over the five-year DSP period, such that steady state is achieved by 2019 with a

79

level of investment of approximately $830 million on average per year, for a total of $4.17 billion over five years.

However, this accelerated strategy would still contain levels of investment that do not align to Toronto Hydro's resources or system constraints, and would result in step-increases in rates for customers.

While Toronto Hydro has determined that the ideal investments in Toronto's distribution system exceed those proposed in this capital expenditure plan, the utility acknowledges customers' price sensitivity and therefore has proposed a more gradually paced 2015-2019 capital expenditure plan intended to arrive at the economically optimal steady state in a gradual manner. The proposed strategy addresses the backlog of investments in a manner that achieves the steady state by 2037. The paced strategy entails a proposed level of investment of $2.49 billion over 2015-2019, or an annual average of just under $500 million. Under this strategy, the backlog of investment remaining after 2019 will continue to be managed between 2020 and 2037, alongside new investments. Such new investments will be planned to manage assets that will reach or exceed their economic end-of-life or useful life criteria, as well as new critical issues that could emerge during this same 2020-2037 period. Toronto Hydro estimates that continuing at this average pace beyond 2020 would result in achievement of steady state by approximately 2037. /C

This gradually paced strategy aligns to Toronto Hydro's resource and system constraints, and is therefore practical to execute. Figure 5 illustrates the required capital investments of both the "accelerated" strategy (on the left) and the "paced" strategy (on the right).

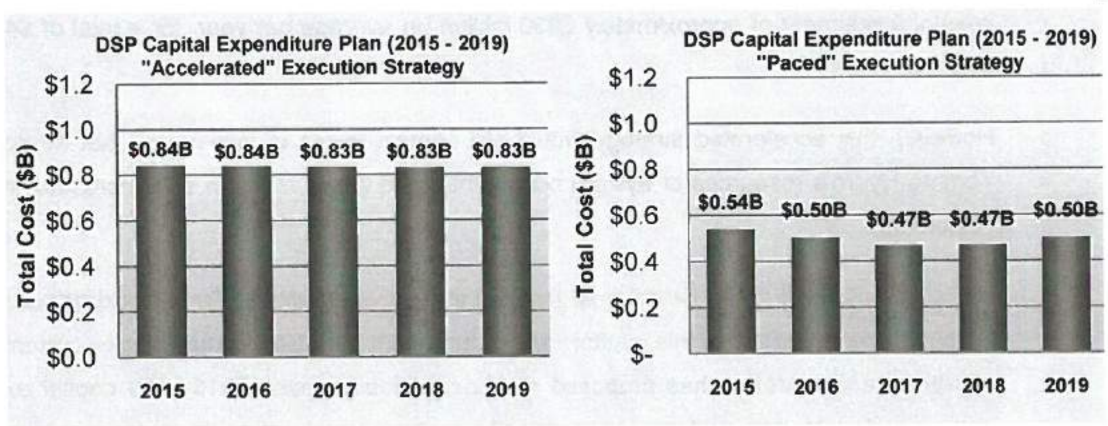

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FIGURE 5: ACCELERATED VERSUS PACED CAPITAL INVESTMENT EXECUTION STRATEGIES (2015-2019)

As previously explained, the steady state is the economically optimal condition for the distribution system and ratepayers. By reaching the steady state in the proposed "paced" manner, the fluctuations in capital investment spending, which are driven by uneven depreciation of the asset base and necessitate periods of significantly large multi-year capital investment above historic levels, can be mitigated, leading to more consistent system-wide performance and smoother rate impacts beyond the initial achievement of steady state in 2037. As noted in the results of Toronto Hydro's customer engagement activities (Exhibit 1B, Tab 2, Schedule 7), some focus group and workshop participants, while accepting of the need for significant capital investment above historic levels and the associated bill impacts, felt that the uneven approach to investment over time could have been avoided had Toronto Hydro been building a reserve of capital funds beforehand. While Toronto Hydro is not able to operate a capital reserve fund of this nature, the paced execution strategy described here could, over the long-term, help mitigate the rate increases that can accompany uneven capital investment commitments.

Under the proposed "paced" execution strategy, SAIFI is projected to be reduced from 1.53 outages in 2014) to 1.13 outages in 2019, and SAIDI is projected to be reduced from 1.21 hours in 2014 to 0.97 hours in 2019 respectively. In contrast, should Toronto Hydro not execute this investment approach and instead adopt a run-to-failure approach, SAIFI and SAIDI are forecasted to worsen by another 30%, and 24% respectively over the period from 2015 to 2019. A run-to-failure approach would force Toronto Hydro to manage assets in a reactive manner, exposing customers to associated outages and higher reactive costs associated with the replacement of assets and the restoration of the system.

(i) "Accelerated" Execution Strategy

The "accelerated" execution strategy is focused on mitigating the backlog of investments within the 5-year DSP period, such that steady state is achieved by 2020.

As illustrated in Figure 10, this strategy requires significant capital investments of approximately $830 million on average per year, with a total five-year investment of $4.17 billion. The advantage of this strategy is that steady state can be achieved in more rapidly, therefore mitigating the risks associated with the backlog within the five-year period. However, it is clear that the rate impacts from this strategy would be substantial for customers. Furthermore, the required investments do not align to Toronto Hydro's available resources and system constraints, and therefore there would likely be execution-related complexities.

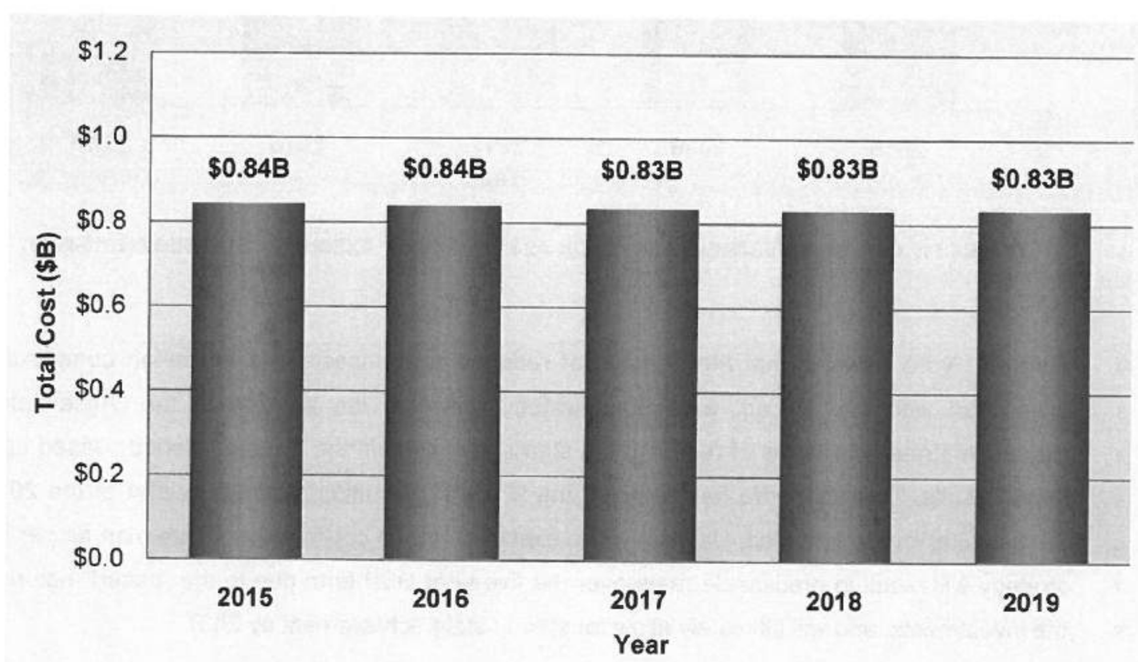

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FIGURE 10: CAPITAL INVESTMENT APPROACH AS PER "ACCELERATED" EXECUTION STRATEGY

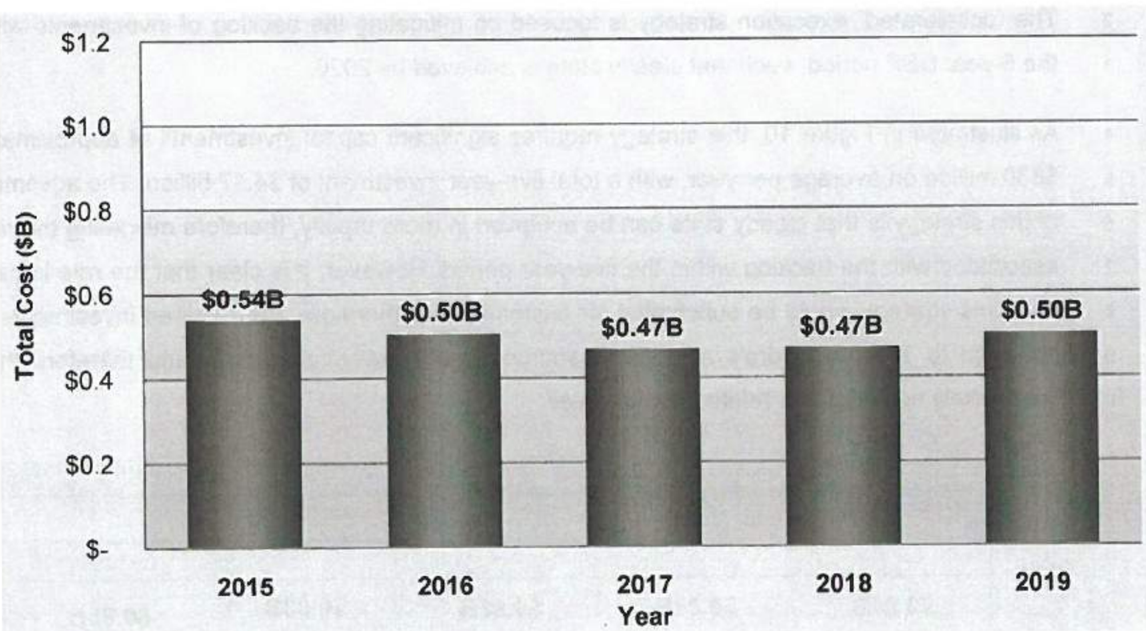

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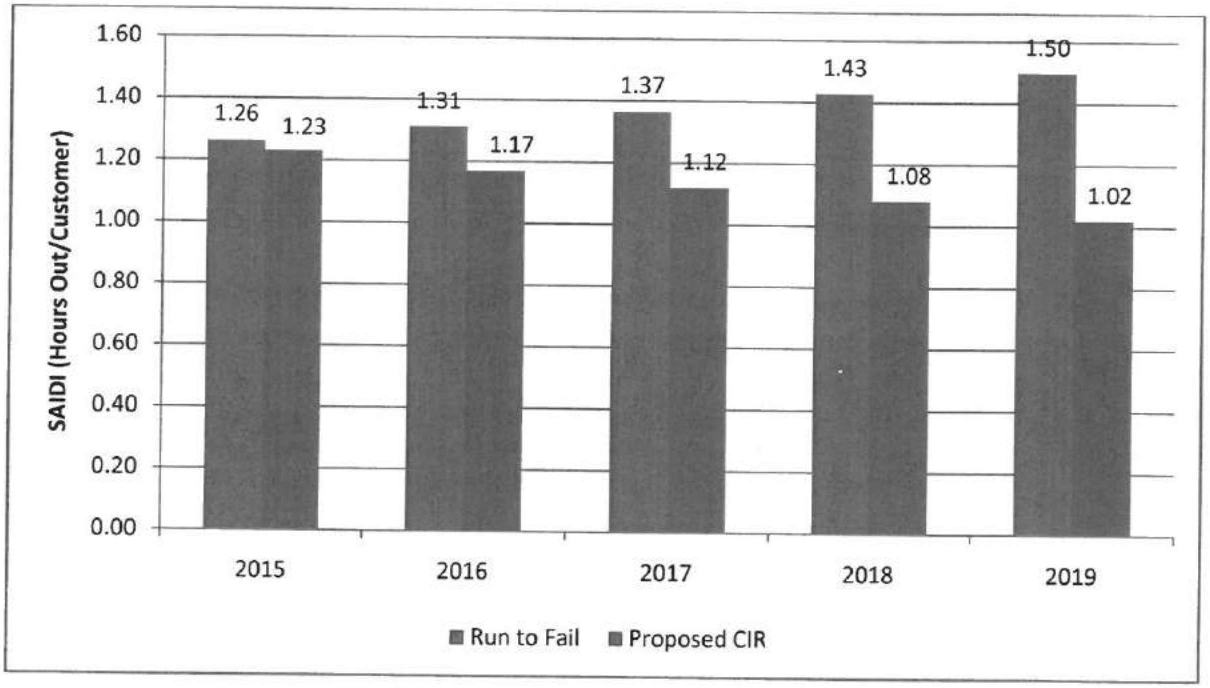
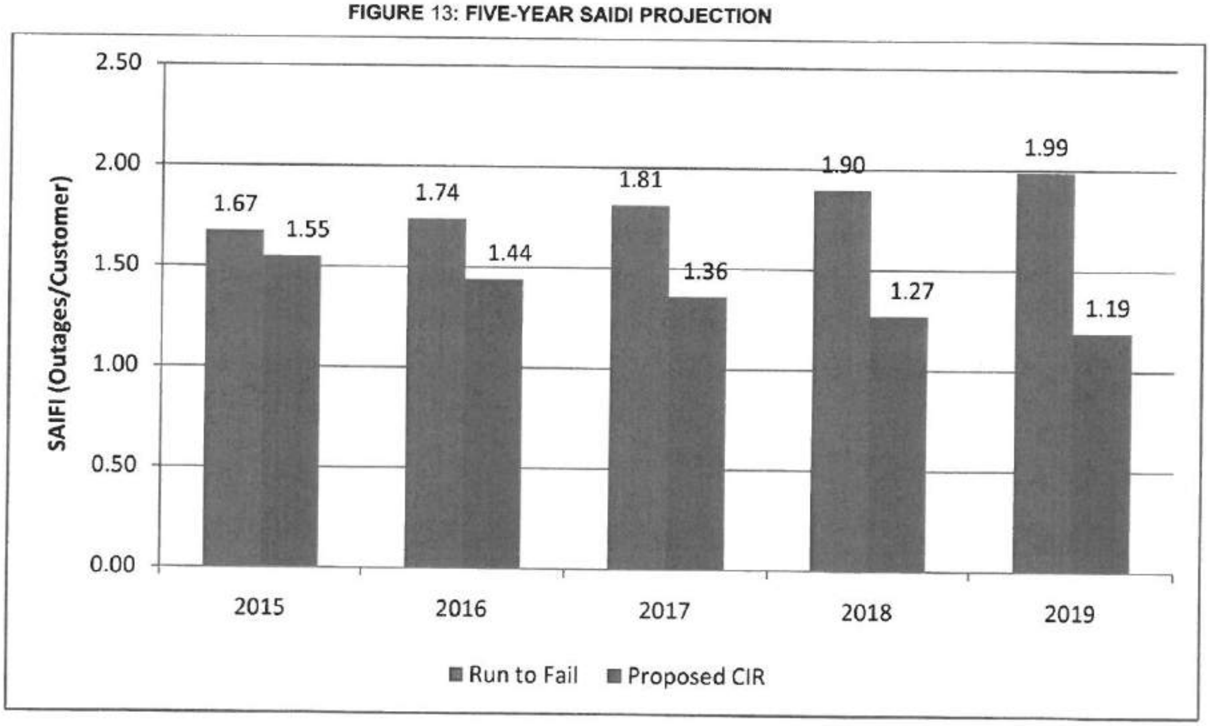
FIGURE 11: CAPITAL INVESTMENT APPROACH AS PER "PACED" EXECUTION STRATEGY (2015-2019)

Toronto Hydro believes that the benefits of reduced rate impacts and execution complexities associated with the "Paced" execution strategy outweigh the benefits of the "Accelerated" execution strategy in terms of reaching the steady state within the five-year period. Based upon these results, Toronto Hydro has selected the "Paced" execution strategy as part of the 2015-2019 capital investment plan. Ultimately, the execution of the capital expenditure plan as per this strategy will result in predictable rates over the five-year DSP term due to the "paced" nature of the investments, and will ultimately allow for steady state achievement by 2037.

Figure 12 illustrates the useful life demographics following the achievement of steady state as per the "paced" execution strategy in 2037. The results illustrate how the replacement value associated with assets past their useful life decrease from 26% as of 2015 to 11% by 2037. Similarly, assets not exceeding their useful lives will increase from 67% as of 2015 to 80% by 2037.



1 **FIGURE 13: FIVE-YEAR SAIDI PROJECTION**



2 **FIGURE 14: FIVE-YEAR SAIFI PROJECTION**

In general, project scheduling and execution must be dynamic in order to manage and account for all of these key elements, while maintaining deployment of resources.

Please see Exhibit 1B, Tab 2, Schedule 4, Appendix A for a detailed description of the complexities in carrying out a large-scale construction project or program in Toronto's dense urban environment.

As per this process, the capital investment plan for 2015 has been based upon Toronto Hydro's current work plan schedule as it stands during the preparation of this evidence.

E2.4 Customer Needs, Preferences and Priorities

As explained in Section E1.6, Toronto Hydro engaged Innovative Research Group ("Innovative") to design and carry-out a consultation process intended to provide the utility with meaningful information to assist in preparing the DSP. The consultation process included randomly recruited, workbook led focus groups, an online workbook accessible to all customers, facilitator led workshops with commercial and industrial users, and finally a statistical telephone survey. Innovative's final detailed report on the process and findings of this consultation is available in Appendix B to Exhibit 1B, Tab 2, Schedule 7.

These findings have provided valuable insight into the needs and preferences of Toronto Hydro's customers and their perception of the utility's priorities. A summary of how key findings are reflected in the DSP follows. The information discussed in the following sections is largely based on results of the final telephone survey, which was administered for the residential and General Service (GS) < 50 kW customer classes. The telephone survey gave Toronto Hydro a detailed view of the preferences of its most populous customer classes. The results of the GS > 50 kW Commercial and Industrial / Manufacturing workshops ("mid-market GS workshops") are referenced below as well, as this was the primary method by which Innovative engaged these larger customer segments.

E2.4.1 Overall Acceptance of Capital Plan

The telephone survey was designed to simulate the experience of customers who had participated in the earlier online workbook and workbook-led consultation sessions. Customers were educated on the state of the system, system challenges and the key aspects of Toronto Hydro's proposed DSP. They were invited to reflect on their personal experience with the system, and were asked to make "value judgments on trade-offs between system reliability and bill

E2.4.2 System Challenges & Priorities

(i) System Reliability

The following survey results describe the recent reliability performance of the system as experienced by the bulk of Toronto Hydro's customers.

- Over half of all customers in both the residential and GS < 50 kW classes have experienced outages during extreme weather events in the last twelve months.[10]
- Not including extreme weather, about half of all customers in these classes have experienced other power outages in the last twelve months.[11]
- 64% of GS < 50 kW customers report direct costs to their businesses as a result of outages.[12]
- Most participants in the mid-market GS workshops had experienced power service interruptions at their businesses in the previous twelve months. Both commercial and industrial customers experienced revenue and productivity losses due to these outages.[13]

As discussed in Sections D and E, Toronto Hydro's asset management policy with respect to system performance is focused primarily on risk-based decision making, where inferred customer interruption costs (CICs) are quantified as one of several risk costs associated with operating aging assets beyond their useful lives. The utility's chosen pace of system renewal is based largely on the objective of balancing these risks against the capital costs of asset replacement so that the total cost of operating the system is minimized over time. While Toronto Hydro does not set specific reliability targets as part of this process, it does project and track the reliability outcomes of its plan and considers adjustments to the prioritization of projects within and across programs if reliability outcomes are tracking below forecasts.

Customer expectations with respect to future reliability performance were captured through the telephone survey. Customers were informed of the current system average outage frequency (i.e. "the average Toronto Hydro customer experiences between one and two power outages per

[10] Ibid., p. 123
[11] Ibid.
[12] Ibid.
[13] Ibid., p. 84

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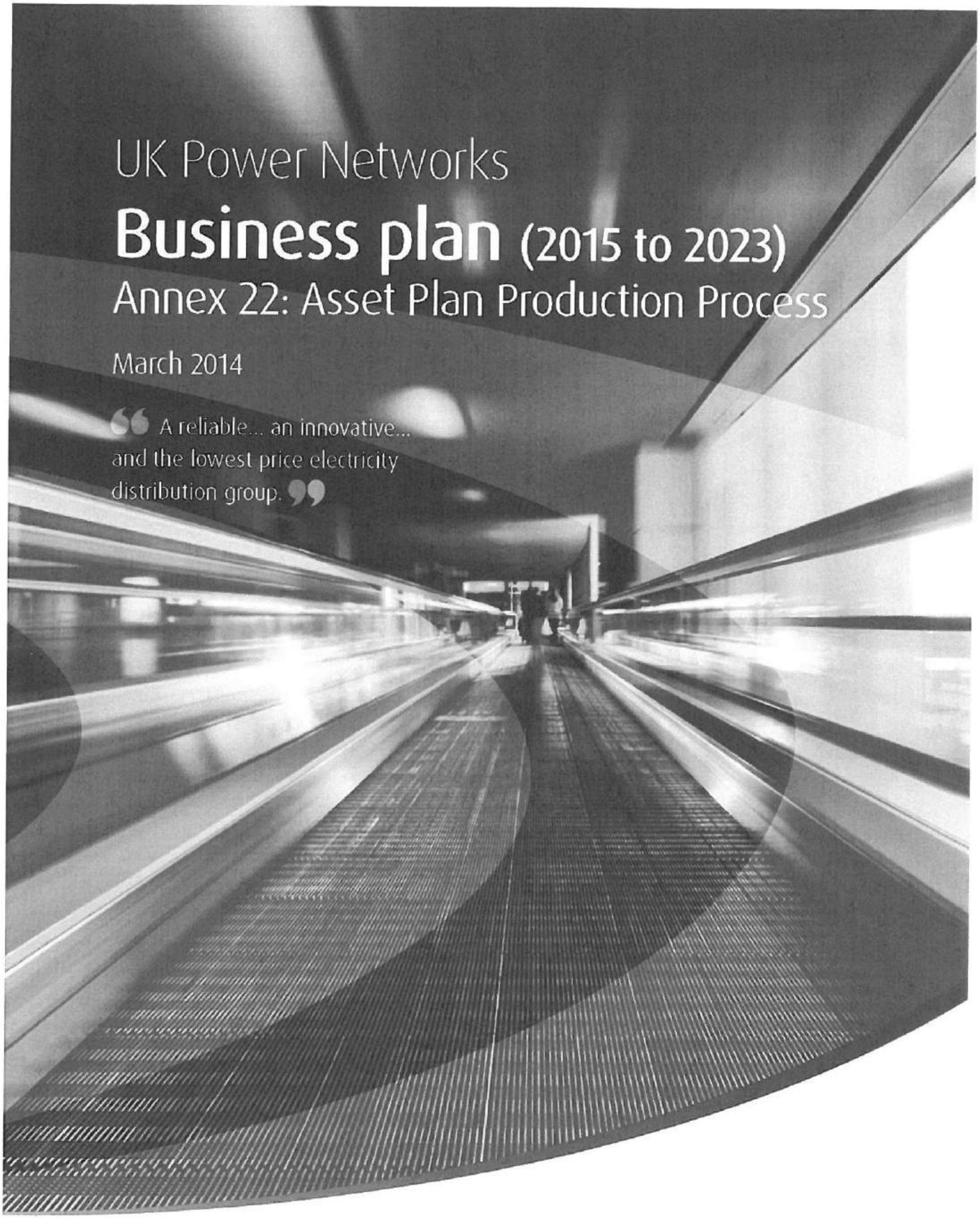

UK Power Networks

Business plan (2015 to 2023)

Annex 22: Asset Plan Production Process

March 2014

“A reliable... an innovative... and the lowest price electricity distribution group.”

UK Power Networks
Delivering your electricity

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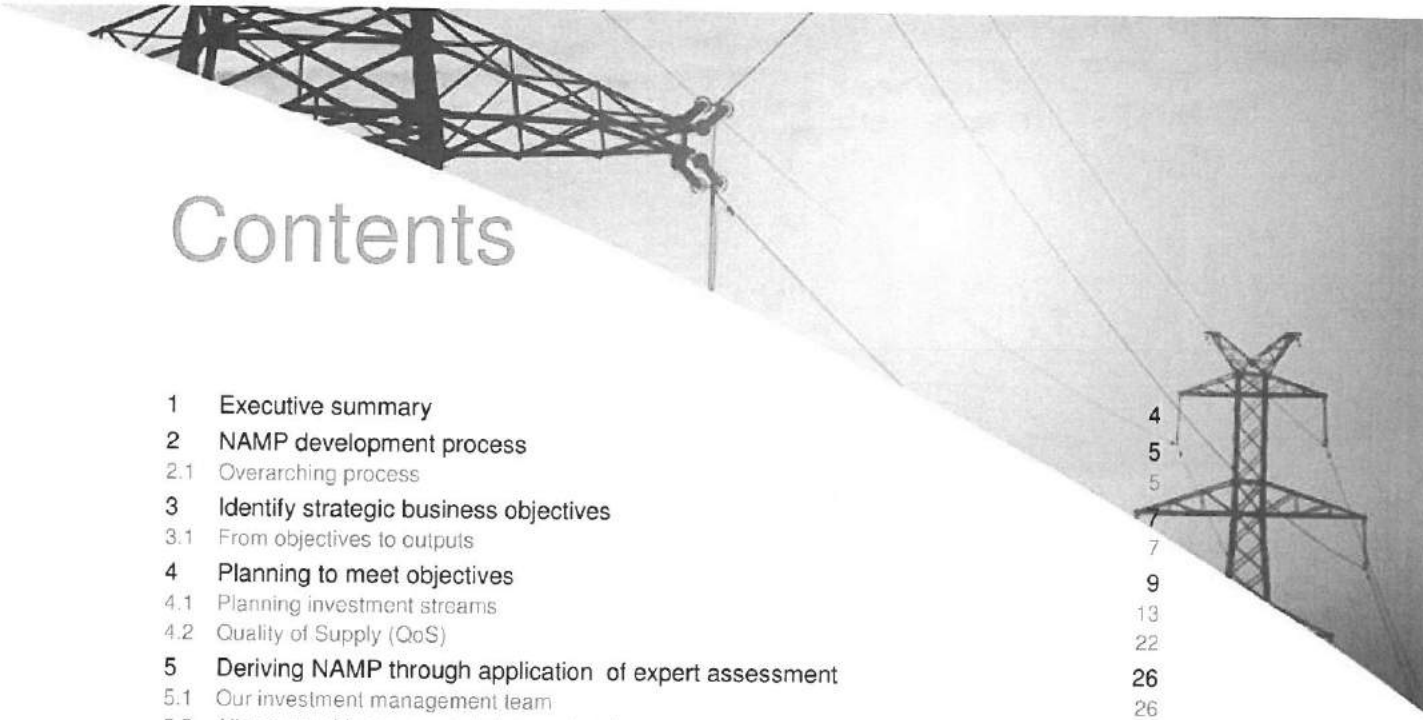
Document History

Version	Date	Revision Class	Originator	Section Update	Details
1.0	09/03/2014		Adrian Searle	N/A	Added March 2014 resubmission front cover



Contents

1 Executive summary

This document explains the overarching process and principles used to derive the Network Asset Management Plan (NAMP) that defines our direct spend for RIIO ED1 period.

The NAMP consists of all of the investment streams that directly relate to expenditure on our network – i.e. direct costs. We assess the need for investment by applying appropriate and proportionate approaches depending on the materiality of the investment stream.

Our industry leading modelling techniques and analytical frameworks provide us with objective analysis upon which to build our investment plans. We enhance this analysis with rigorous expert assessment that incorporates a broad range of considerations (stakeholder input, history, local knowledge, innovation insights), all working within our asset management strategy and policies.

This human enhancement of modelled output allows us to develop robust and justified sets of investment need cases – that can see either increases or decreases in the volume of activity compared to the raw modelled output. These adjustments seek to ensure that we plan to undertake activities based on the fullest possible consideration of the information available.

We translate each of the need cases into engineering options through a robust process that consists of: considering potential solutions, short-listing and finally identifying the scheme that delivers the greatest long term value for customers while meeting our obligations. Taken together these individual decisions on work are brought together to form a complete efficient investment stream to deliver the required outputs, e.g. non-load related (NLRE), load related (LRE) or quality of supply (QoS).

The individual investment streams are aggregated into the NAMP through an optimisation process that seeks to ensure that the interactions between streams are recognised and the objectives and outputs appropriately balanced.

We then test the full NAMP to ensure that it is consistent, well-justified and robust within the bounds of uncertainty, deliverability and financeability.

2 NAMP development process

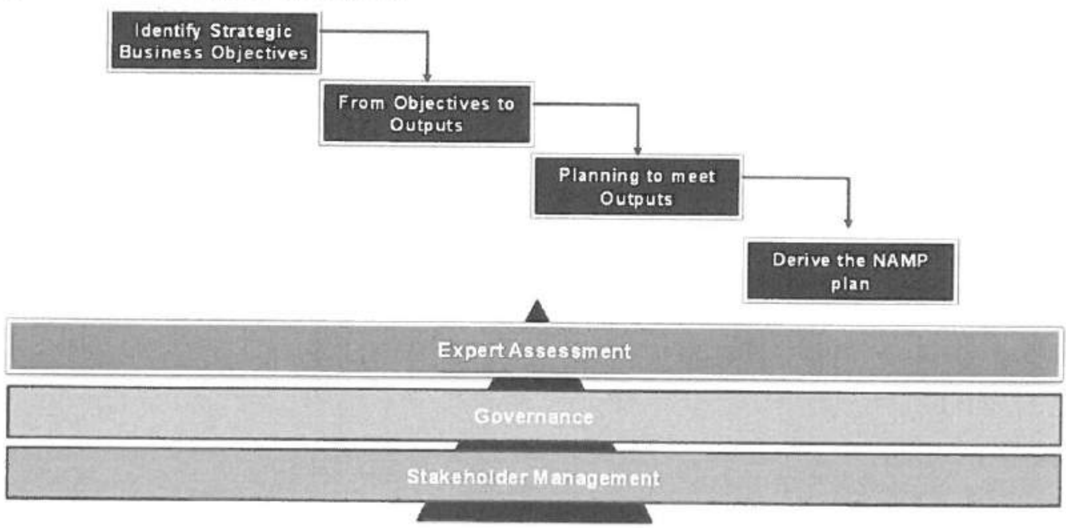
The Network Asset Management Plan (NAMP) contains the company's best view of investment needed in each of our networks to meet outputs and commitments during the RIIO ED1 period (from April 2015 to end of March 2023). The investment projections incorporated in the NAMP relate to all of the expenditure on our network – i.e. what is termed our direct capital and direct operating costs.

2.1 Overarching process

The NAMP is produced on a rolling basis, updated annually and feeds directly into the production plan used by our delivery functions.

We follow a robust process that links the business' direct expenditure to the objectives and the outputs we have committed to deliver. Figure 1 provides an overview of the steps taken to develop the NAMP.

Figure 1 NAMP development framework



The NAMP development process consists of:

1. Identifying strategic business objectives aligned to our stakeholders views and committed outcomes
2. Translating the high level objectives to the outputs we have committed to deliver
3. Developing detailed planning analysis to meet our objectives and outputs
4. Deriving the efficient volume and cost NAMP

Throughout the process we apply expert assessment and work with internal and external stakeholders to enhance and test our plans (e.g. seeking input on the balance of competing objectives, ensuring compliance, assessing economic efficiency and resilience to uncertainty).

The NAMP development process is subject to strict governance procedures. These define the approval authorities, roles, responsibilities and procedures that need to be adhered to when adding or changing the expenditure for investment projects included in the NAMP. In addition to that, we expose some key inputs and outputs to thorough scrutiny by our stakeholders (see chapter 7 for more details).

3 Identify strategic business objectives

The first step in the development of the NAMP is the identification of overarching strategic business objectives. These were developed within a process encompassing the whole business and signed-off by the Executive Management Team (EMT). The EMT has established these business plan objectives within the framework of our overarching corporate objectives (i.e. Employer of Choice, Respected Corporate Citizen and Sustainably Cost Efficient).

Below are (in no particular order) relevant strategic objectives that have been used to guide the NAMP development process;

- Invest (opex and capex) at the lowest long-term cost to manage the health and risk of the network thus avoiding detrimental impact on the outputs that are important to our stakeholders
- Invest at the lowest long-term cost to support the anticipated needs of a future carbon conscious network through the delivery of outputs that our customers value Operate our customer processes to deliver sustained customer satisfaction and performance
- Inform the regulatory outputs to recognise our approach to long-term improvements in safety
- Respond to society's existing and evolving expectations of social obligations to deliver value to the business

The application of these strategic objectives is discussed further in the context of Asset Management in our "Meeting Business Objectives" document.

3.1 From objectives to outputs

Our strategic objectives have been translated to specific commitments and outputs for the RIIO-ED1 period.

We have used extensive stakeholder engagement to develop our strategic objectives into the outputs and commitments. You can find more on our engagement programme in our Process Overview document that forms part of our Business Plan[1].

The decision on the outputs and commitments falls to our Executive team. They take into account a full range of expert assessment and information from stakeholder feedback, our networks' performance, in-progress innovations and our vision to be in the top third performance amongst our peers.

Table 1 below reports the overarching business objectives and their respective outputs where relevant to the NAMP development process.

Table 1 Output category mapping

Output category	Primary Output	Secondary deliverable
Reliability and	• Customer interruptions (CI) - planned	• Health Index (HI)

[1] UK Power Networks, 2015 to 2023 Business Plan Update, Incorporating stakeholder feedback, April 2013

Output category	Primary Output	Secondary deliverable
availability	• Customer interruptions (CI) - unplanned • Customer Minutes Lost (CML) – planned • Customer Minutes Lost (CML) - unplanned	• HI Criticality and Risk Index (RI) • Load Index (LI) • Resilience • Worst served customers (WSC) • Guaranteed Standards of Performance (GSoP)
Customer Service	• Customer Satisfaction Survey • Complaints Metric	
Connections	• Time to connect • Major Connections Stakeholder Engagement	
Environment	• Business Carbon Footprint (BCF) • Innovation Funding	• SF6 and oil leakage • Undergrounding in Areas of Outstanding Natural Beauty (AONB)
Safety	• Compliance with HSE (Health & Safety Executive) legislation and directives	• Asset Health, Criticality and Risk Index – see Network Reliability. This provides a framework for managing risk including safety • Number of fatal major and lost time contractor accidents • Number of public injuries (resulting from our activities)
Social	• Zero Harm • Public safety awareness	• Provision of PS (Priority Service) Register • Fuel poverty

4 Planning to meet objectives

Our investment planning process is based on a series of workstreams. These provide the analysis to support the investments we consider are required to meet our business objectives and deliver the output measures we have committed under RIIO ED1.

The key investment streams are:

- Load Related Expenditure (LRE)
- Non Load Related Expenditure (NLRE)
- Quality of Supply (QoS)

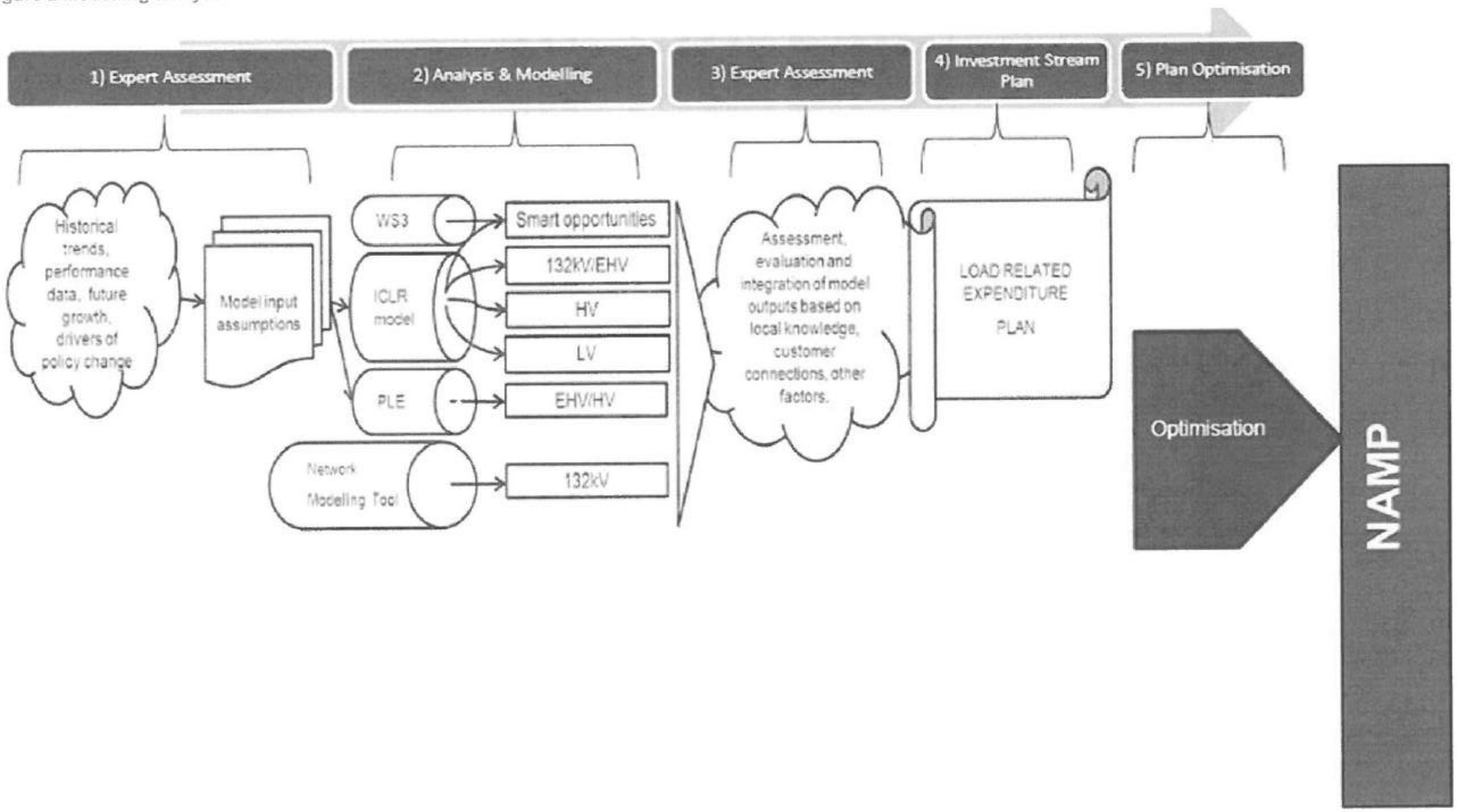
Within each investment stream, our approach to asset management and our use of industry leading modelling techniques provides a deep understanding of the issues and robust evaluation of the investment drivers. Together they form the basis of our business case and robust justification for each efficient investment project in each stream to ensure we can efficiently deliver our commitments and outputs.

Figure 2 illustrates the overarching analytical framework used to derive the individual investment stream plans, and each of the stages is described in more detail below.

Expert assessment (step 1) inference from stakeholder engagement, historical trends, performance data etc, is used to derive the relevant **input assumptions** to the models and analysis. These are then used within the investment stream **specific analysis and model frameworks** (step 2). For example, for the asset replacement plans within the NLRE the tools used are the Asset Risk Prioritisation (ARP) models. These models are tailored to provide accurate forecasting of health and criticality indices to each asset group categories (e.g. substations, switchgear, etc.).

Expert assessment (step 3) is then rigorously applied to the model outputs in order to test the proposed investment programmes against factors such as historical trends, regional factors, site specific knowledge and the requirements of our asset policies. The refined outputs (i.e. the investment programmes) (4) are subsequently integrated into our Network Asset Management Plan (NAMP).

Figure 2 Modelling analytical framework



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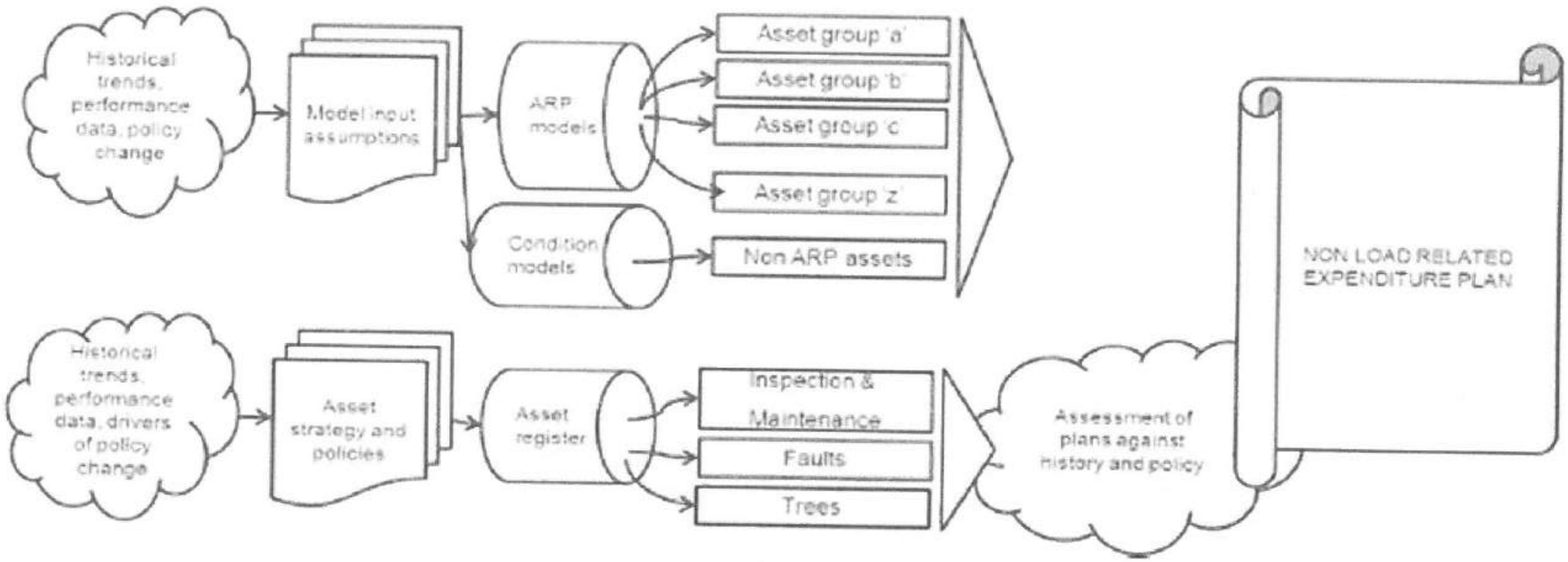
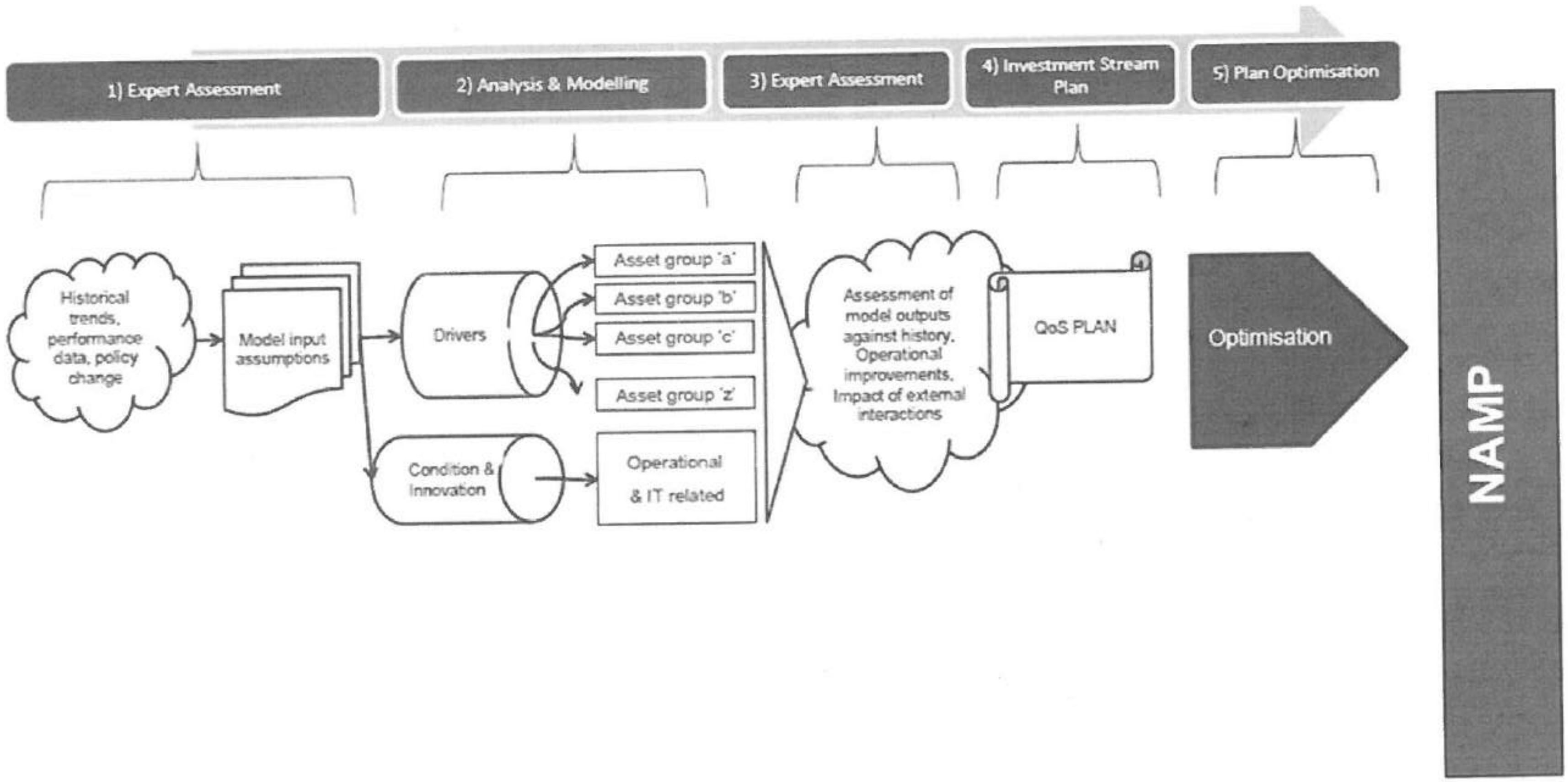


Historical trends, performance data, policy change
Model input assumptions
ARP models
Condition models
Asset group 'a'
Asset group 'b'
Asset group 'c'
Asset group 'z'
Non ARP assets
Historical trends, performance data, drivers of policy change
Asset strategy and policies
Asset register
Inspection & Maintenance
Faults
Trees
Assessment of plans against history and policy
NON LOAD RELATED EXPENDITURE PLAN


1) Expert Assessment
2) Analysis & Modelling
3) Expert Assessment
4) Investment Stream Plan
5) Plan Optimisation
Historical trends, performance data, policy change
Model input assumptions
Drivers
Asset group 'a'
Asset group 'b'
Asset group 'c'
Asset group 'z'
Condition & Innovation
Operational & IT related
Assessment of model outputs against history. Operational improvements. Impact of external interactions
QoS PLAN
Optimisation
NAMP

100

4.1 Planning investment streams

As previously discussed the NAMP has three key investment streams. Table 2 provides an overview of the three investment streams and the significant subcomponents.

Table 2 Planning Investment streams

Investment stream	Subcomponents
Load Related Expenditure (LRE)	• General Reinforcement • Diversions • National Grid related expenditure • Connections related expenditure
Non Load Related Expenditure (NLRE)	• Capex: – Asset Replacement – Asset Refurbishment – ESQCR (Electricity Supply, Quality & Continuity Regulations) – Civil Works • Opex: – Inspection & Maintenance – Faults – Trees
Quality of Supply (QoS)	• Quality of Supply investments • Operational IT (Information Technology) & Telecoms

Below we describe the individual investment streams. For each, we focus on highlighting the objectives, modelling techniques used, expert assessment applied and relevant interactions with other streams.

4.1.1 Load Related Expenditure (LRE)

The Load Related Expenditure Objective for RIIO ED1 is to maintain the overall network risk, based on assessment of utilisation - as indicated by our Load Index (LI) categories 1 to 5.

We assess the utilisation of our networks and seek to maintain the number of sites in our LI 4/5 categories (using our existing categorisation) broadly the same over time. The change of definition of LI, will mean LI4/5 is no longer an indicator of the need for intervention. However, we will continue to assess the need case for investment on the expected utilisation of assets, evaluating the opportunities for operating above the firm site capacity e.g. using smart technologies and our expertise in running our assets efficiently, while employing innovation and smart interventions to mitigate uncertainty around future load growth.

To achieve the LI objective we use the following models in order to predict the future demand growth on our networks and inform our investment decisions, e.g. around application and benefits of smart technologies:

- [Element Energy (EE)] Demand forecasting tool
- Planning Load Estimates (PLE)
- The Imperial College developed Load Related model (ICLR)
- Smart Grid Forum Work Stream 3 (WS3) Transform model
- Table 3 provides an overview of the four different models.

Table 3 LRE models

LRE Models / Frameworks	Overview
Element Energy	• Load growth model projecting future demand trends • Based on economic and technology factors[2]
Planning Load Estimates[3]	• Site specific investment model that supports decisions around the need for investment at HV and EHV substations, highlights constraining factor (which may include in/out bound circuits). • Ensures P2/6 compliance • Provides key outputs to meet the full range of statutory and licence requirements • Supported by Regional Development plans that record specific site by site drivers of demand growth • Uses Element Energy model output for load growth assumptions
Imperial College Load Related	• Innovative system level model • Models total system demand at all voltage levels (LV, HV, EHV and 132kV) • Flags constraints on all assets (circuits, substations, switchgear etc.), for a range of conditions, thermal, voltage, fault-level • Provides longer term view and allows alternative scenarios to be modelled to aid the understanding of the impact of Low Carbon technologies on the network • Uses Element Energy model for load growth assumptions
Transform (Smart Grid Forum, Work stream three -WS3)	• Models generic network types nationally to provide an indication of what and how smart could be deployed and indicative financial benefits • Our own models and expert analysis provide specific opportunities for smart based on a full understanding of our network topology and operating constraints that demonstrate how our plans fit within the envelope smart benefits suggested by the Transform model

The models described in the table above provide complementary perspectives regarding future LRE network requirements and we use the outputs of these models through the application of expert assessment. For example, the ICLR and PLE models are used:

- Individually when the results are not comparable in terms of outputs modelled (e.g. the PLE provides a site specific view whilst the ICLR also provides outputs relating to the system as a whole) or in terms of network modelled (e.g. the PLE does not provide a view on Low Voltage investment requirements; whilst the ICLR does)
- Jointly when their output is comparable, but complementary perspectives to the same problem are required (e.g. the PLE model is more likely to better identify constraints earlier than the ICLR as the former is a site specific model whilst the latter is a system maximum one)

The result of the modelling exercise provides a range of outputs and information that we use to develop our investment plan. In doing so, a complex set of factors and expert assessment will be taken into account to obtain the best engineering solutions that meet the committed objectives. This includes:

- Examining the opportunity of adopting non network related solutions to address the issue
- Estimating the impact on Quality of Supply of the alternative solutions

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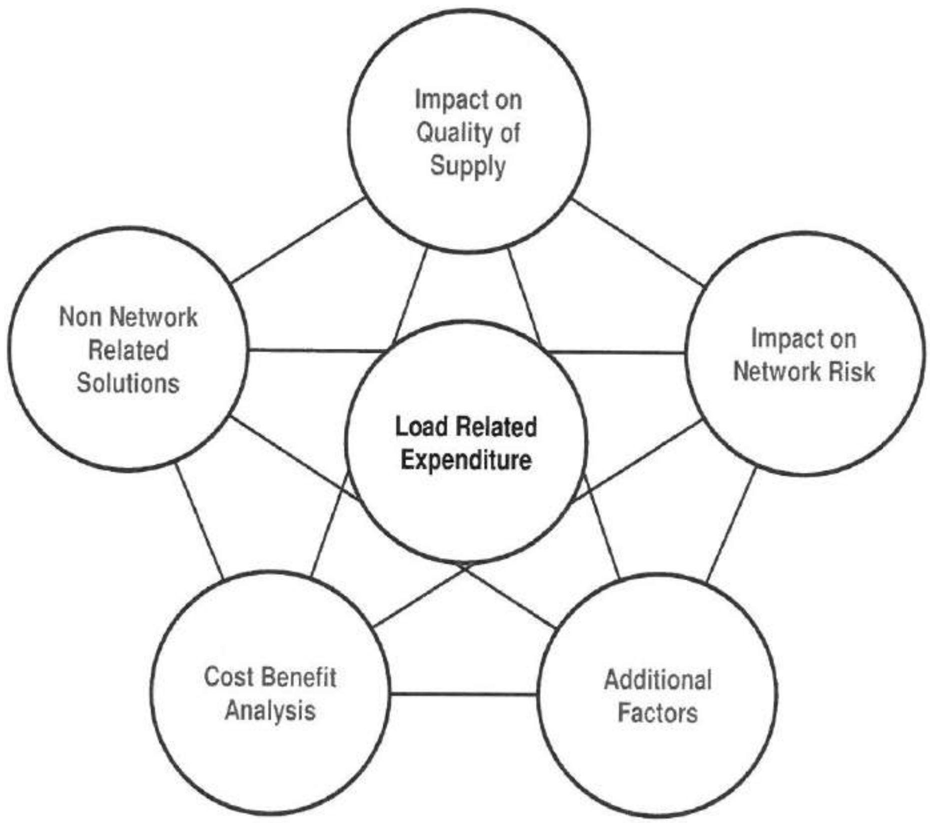
[2] Examples of economic growth factors include population growth and domestic thermal efficiency whilst technology factors include heat pumps uptake and onshore wind generation plans.

[3] A comprehensive description of the Planning Load Estimator model can be found in EDP 08-106

- Assessing the impact on network risk of alternative solutions
- Considering the impact of additional factors on the model outputs (e.g. the impact of distributed generation)
- Undertaking a cost benefit assessments of alternative options

Figure 3 provides an overview of the factors taken into account

Figure 3 Load Related Expenditure factors



These are discussed in detail in Table 4.

Table 4 LRE Investment Plan Development factors

LRE investment plan development factors	Description
Non Network Solutions	• Assess the alternative options of adopting Demand Side Response (DSR) solutions • Assess the alternative options of increase capacity by operational measures • Assess other relevant non-network asset options
Impact on Quality of Supply	• Assess the benefit (risk) of investment (deferred investment) on QoS • Assess mitigation actions if non-investment decision is taken
Impact on Network Risk	• Assess long term impact on overall network risk • Assess the risk of increased probability asset degradation as a consequence of deferred investment • Assess the increase in regional network risk e.g. from increasing load transfers against a scenario of uncertain load growth forecasts • Assess mitigation actions if necessary

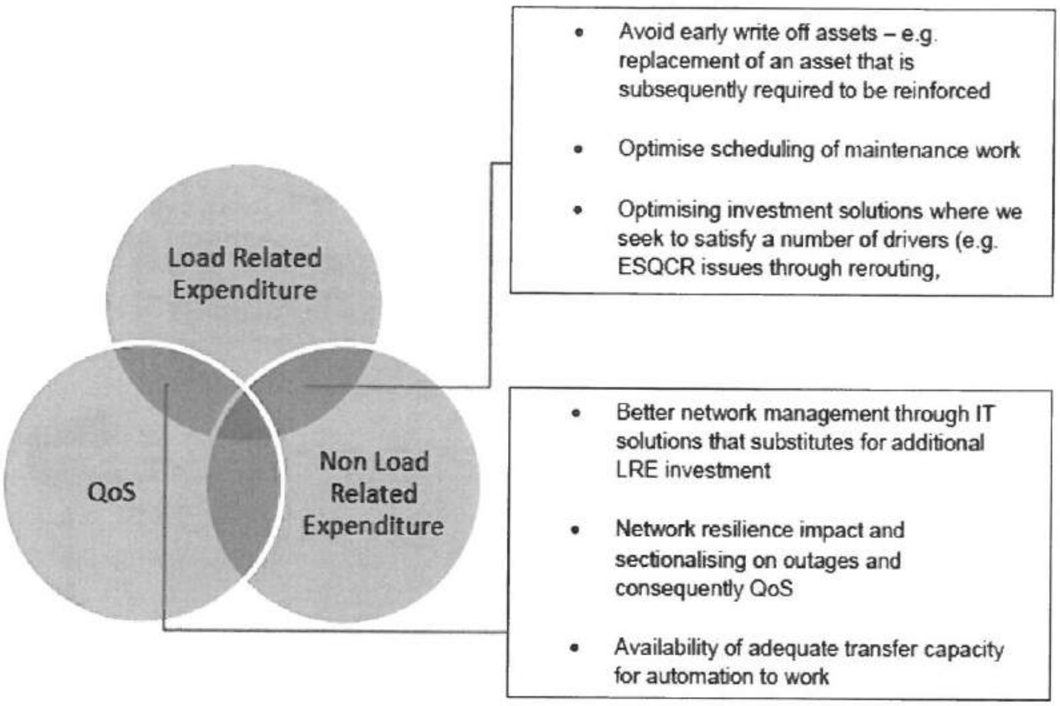
LRE investment plan development factors	Description
Additional Factors	• Assess the potential for innovative solutions • Assess the impact of Connection applications • Assess the impact of Low Carbon technologies • Assess the impact of broader network development considerations (e.g. National Grid connections) • Assess the impact of distributed generation • Use Local knowledge of the assets • Assess the impact of future local authorities development plans • Assess the impact of future Network Rail development plans • Assess the impact on interlinked and sequenced projects (e.g. there may be dependencies such that adding capacity at a site is dependent on capacity being built available elsewhere first) • Assess other site specific factors
Cost Benefit Analysis	• Consider the long-term cost/benefit analysis of alternative options • Assess the alternative options e.g. capacity vs load transfers vs auto-reconfiguring the network • Assess on a regional basis to ensure an appropriate portfolio of solutions to maintain flexibility and avoiding lock-in to particular strategies

By taking into account the factors and expert assessment illustrated above, the Asset Management teams establish the most effective solution to meet the committed outputs for RIIO ED1. Senior managers within the Asset Management function provide rigorous challenge to their respective teams by exploring the considerations described above before a final endorsement by the Director of Asset Management.

In particular the balance of types of projects (e.g. interconnection, capacity addition or demand side response etc.) within the plan would be scrutinised to reflect expectations from past experience and uncertainties of future load growth. This is particularly relevant as small increases in capacity are not always the most economical solution for the long-term flexibility for a region. In producing the overarching Load Related Expenditure investment plan, we apply additional expert assessment as detailed in chapter 5.

It is also important to note that the Load Related Expenditure investment plan interacts with the other streams as detailed in Figure 4 below.

Figure 4 LRE investment plan interaction with other streams



4.1.2 Non Load Related Expenditure (NLRE)

The Non Load Related Expenditure Objectives for RIIO ED1 are:

- Achieve compliance and minimise the risk to the members of the public and employees
- Maintain the networks' asset health risk broadly constant over the period. This is measured by the Health Index (HI) categories 1- 5 and the Criticality Index (C) categories 1 – 4
- Achieve our forecast CI targets and improve processes and target inspection and maintenance interventions (I&M) at those assets and features that are recognised (e.g. type of failures) or believed to be the most problematic, unless replacement is the more appropriate option
- Achieve a resilient network by maintaining compliance with the ENA Technical Specification 43-8 on tree cutting (ETR132)

In order to achieve the above mentioned objectives we seek to maintain the number of assets with HI4/5 categories between the start and end of RIIO ED1 period broadly constant.

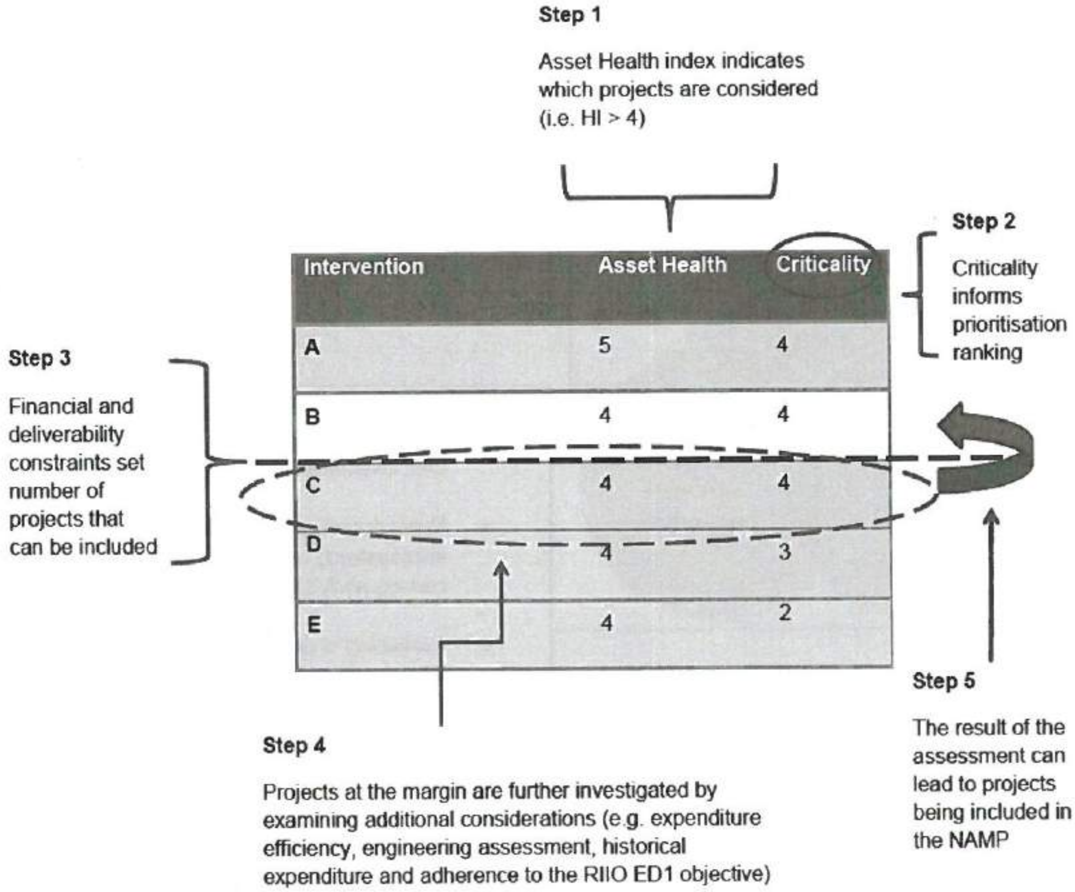
The first step in this process estimates the number of HI4 / HI5 categories at the beginning and end of RIIO ED1 by asset classes. This provides a provisional number of interventions that need to be included in the investment plan based on the deterioration profiles for our assets.

In establishing which intervention should be prioritised, we look at asset criticality. This measure considers the consequences of failure of an asset in each of the following categories: network, safety, environmental and financial risks as a result of failure.

Given our finite financial and delivery capacity, we prioritise the interventions to those that deliver the greater risk reduction per pound spend. There will be projects that are clearly high priority and those that are clearly low priority. Where we draw a line across our prioritised list we apply additional expert scrutiny to ensure the right projects are included in the plan considering the full range of information, risks and efficiency opportunities to best meet our objectives.

Senior managers within the Asset Management function use this assessment to challenging their respective teams on the broadest range of considerations like expenditure efficiency, engineering assessment (e.g. acceptable levels of risk), historical expenditure and adherence to the RIIO ED1 objective. The result of this challenges the priority of the projects around the margin to ensure the best balance of the asset management objectives.

Figure 5 NLRE Project Assessment process



To identify the future Asset Health and interventions' Criticality across our asset base we apply the following models:

- Asset Health models (e.g. Asset Risk and Prioritisation – ARP - models, Civil Asset Health models, etc.);
- Criticality models (e.g. Criticality models relating to Asset Health, Criticality models relating to ESQCR interventions, etc.).

Table 5 below provides an overview of the different models used.

Table 5 NLRE models

NLRE Models / Frameworks	Overview
Asset Health (ARP) [4]	• Provides a numeric representation of the condition of each asset, known as Health Index (HI) • Uses condition information (e.g. age, location, inspection data, etc.) to derive the HI (Health Index) • Provides comparable measures of condition for individual assets in terms of proximity to end of-life (EOL) and probability of failure (POF) • Makes predictions on the change of HI over time, future failure rates, and how these

[4] Further information on ARP models can be found in Annex 22: Asset Plan Production Process

NLRE Models / Frameworks	Overview
	might be affected by different intervention strategies over specified lengths of time • Provides information on the appropriate window for replacement / refurbishment reflecting our asset management strategy and individual policies
Asset Health (Civil) [5]	• Provides a numeric representation of the condition of each asset, known as Health Index (HI) • Uses condition information to derive the HI (1 to 4) • Provides a trigger for intervention (improve the condition of asset categories 3 and 4 into asset categories 1 and 2)
Asset Health (Other)	• Stocks & Flows / SARM
Criticality (ARP)	• Provides a relative comparison of the consequences of failure within the Health index categories by assigning a criticality score (1 to 4) • The criticality score is based on the consequences of failure from a network performance, safety, environmental and financial perspective
Criticality (ESQCR)	• Assigns a severity score indicating the deadline within which issues needs to be resolved • The severity score is based on the following defect categories: Regulatory Risk, Safety Risk, Environmental Risk, Quality of Supply Risk, Financial Risk • The results feed into the Criticality (ARP) model

The application of the models mentioned above, and ARP in particular, allows us to better look across a range of asset types to ensure that we are managing asset risk consistently across our network assets. This, combined with the information derived from criticality models and expert review, provides a holistic view of our asset replacement programme.

The results of the modelling exercise allow us to forecast the future health condition of our network, compare it with its status at the beginning of RIIO ED1 and identify the number of interventions needed to keep the health risk broadly equivalent between the start and the end of the regulatory period. The criticality outputs inform our decision of which assets should be prioritised when undertaking the planned interventions.

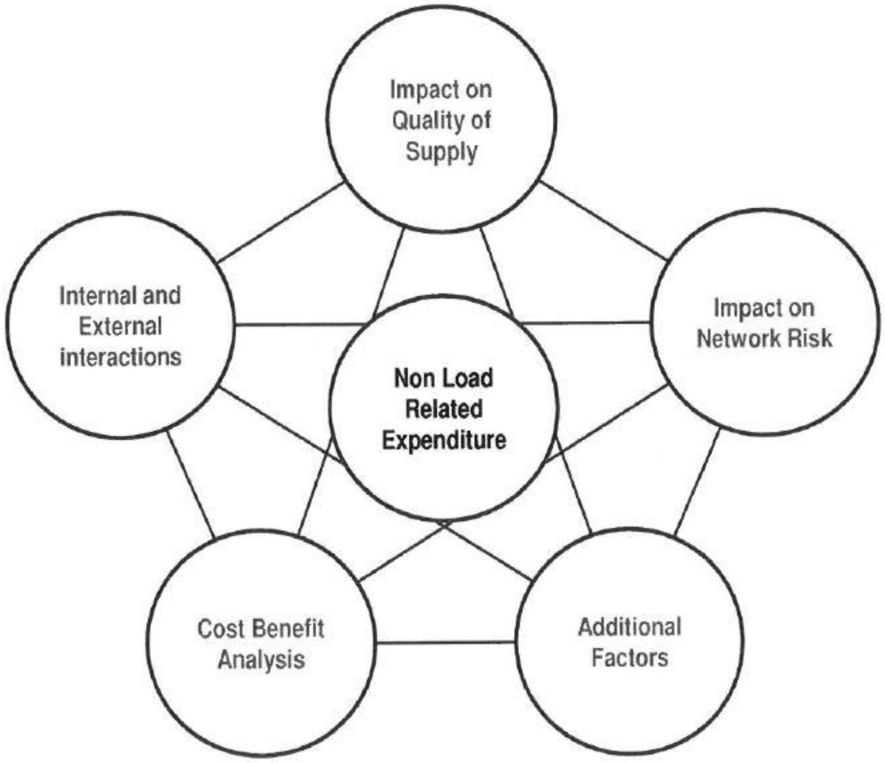
A set of additional considerations and expert assessment is taken into account when developing the NLRE investment plan. This includes:

- Understanding and managing the interactions within and external to the NLRE stream
- Considering any impacts on Quality of Supply of the alternative solutions
- Assessing the impact on network risk of alternative solutions
- Considering the impact of additional factors on the model outputs
- Undertaking a cost benefit assessment of alternative options

Figure 6 provides an overview of the factors taken into account.

[5] Further information on the Civil Works modelling can be found in Document 10, Asset Category – Civils (Capex & Opex)

Figure 6 NLRE investment plan development



These are discussed in detail in Table 6.

Table 6 NLRE Investment Plan Development factors

NLRE investment plan development factors	Description
Internal and External Interactions	• Manage and address interactions within non-load stream (see below) • Manage and address interactions across investment streams(see below)
Impact on Quality of Supply	• Assess the benefit (risk) of intervention (non-intervention) on QoS • Assess mitigation actions if non-intervention decision is taken
Impact on Network Risk	• Assess long term impact on overall network risk • Adopt mitigation actions if necessary
Additional Factors	• Assess the potential for innovative solutions • Industry best practice • Knowledge of our assets and the operational performance • Knowledge of local circumstances • Asset strategy and policy • Previous forecasted activity • Actual historical performance • External climate and natural events (e.g. flooding) • Impact on faults of adopting new technologies early (e.g. in the case of polymeric cables)
Cost Benefit Analysis	• Whole Life Cost analysis of alternative options • Understand the different economic benefits and trades off of replacement / refurbishment / maintenance

By taking into account the factors and expert assessment mentioned above, the Asset Management teams establish the most effective solution to meet the committed outputs for RIIO ED1. Ultimately, in producing the overarching NAMP, we apply additional expert assessment checks as detailed in chapter 5.

As detailed in Table 7 the NLRE internal interactions are particularly important in determining optimal intervention strategies and consequently the overall investment stream plan.

Table 7 below provides an overview of these internal interactions.

Table 7 NLRE internal interactions

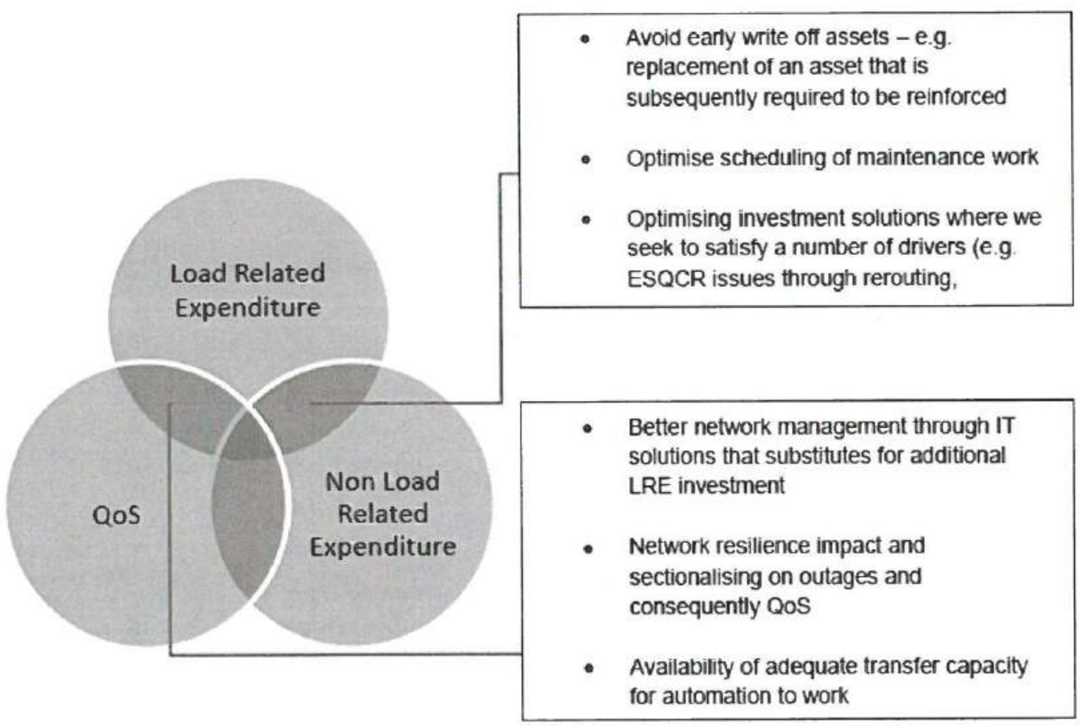
Investment sub-stream	Interaction with...	Interaction description
Refurbishment Replacement	ESQCR	• ESQCR enhancing intervention
	Civil Works	• Optimisation of scheduled maintenance
	Inspection and Maintenance	• Asset records • Number of visits • Ease of fix • Intervention scheduling optimisation
	Faults	• Historical trend analysis
	Trees	• Intervention on OHL (overhead lines)
ESQCR	Refurbishment	• ESQCR enhancing intervention
	Civil Works	• ESQCR enhancing intervention • Land owner consent
	Inspection & Maintenance	• Asset Records
	Faults	• Historical trend analysis
	Trees	• Land owner consent
Civil Works	Refurbishment / Replacement	• Optimisation of scheduled maintenance
	ESQCR	• ESQCR enhancing interventions
	Inspection & Maintenance	• Asset records
	Faults	• Historical trend analysis
	Trees	• Vegetation clearance
Inspection & Maintenance	Refurbishment / Replacement	• Asset records • Number of visits • Ease of fix • Intervention scheduling optimisation
	ESQCR	• Asset records • Number of visits
	Civil Works	• Asset records • Number of visits
	Faults	• Historical trend analysis • Asset records • Number of visits
	Trees	• Asset records • Number of visits
Faults	Refurbishment / Replacement	• Historical trend analysis

Investment sub-stream	Interaction with…	Interaction description
Faults	ESQCR	• Historical trend analysis • Detection of issues
	Civil Works	• Historical trend analysis • Enhance Flood protection
	Inspection & Maintenance	• Historical trend analysis • Asset records (Defects)
	Trees	• Historical trend analysis • Fault numbers
Trees	Refurbishment / Replacement	• Intervention type on OHL
	ESQCR	• Land owner consent
	Civil Works	• Vegetation clearance
	Inspection & Maintenance	• Asset records
	Faults	• Historical trend analysis • Fault numbers

When assessing alternative options the Asset Management teams also take into account NLRE interactions with the other investment streams.

Figure 7 provides an overview of these interactions.

Figure 7 NLRE Investment determination considerations



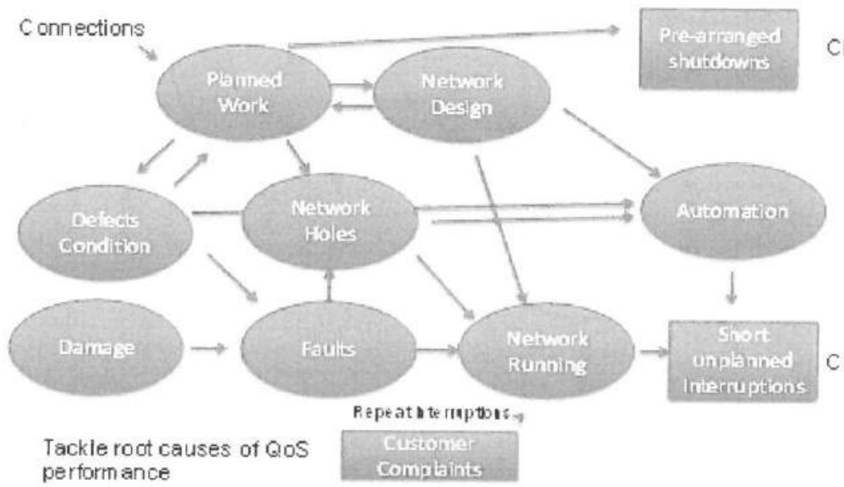
4.2 Quality of Supply (QoS)

The Quality of Supply objectives for RIIO ED1 are:

- Improve quality of supply in all three licence areas so that their CI and CML performance during ED1 is in the top third compared to other DNOs (Distribution Network Operators)
- Improve on the number of restorations within 12 hours by 30%
- Optimise cost benefit from the ED1 Interruptions Incentive Scheme and other Customer Service Incentives
- Maintain the existing SCADA (Supervisory Control and Data Acquisition) capabilities to support any future smart grid innovation that will enable the network to run more effectively

In order to achieve this objective, we take a holistic view of QoS performance drivers, as illustrated in Figure 8, and track performance through industry reporting and benchmarking. We would also take into account historical trends and technology developments to inform our analysis.

Figure 8 QoS drivers



In addition to that analysis, a complex set of additional considerations and expert assessment is also taken into account when developing the QoS strategy (see Annex 6: Quality of Supply Strategy)

Figure 9 QoS investment plan development

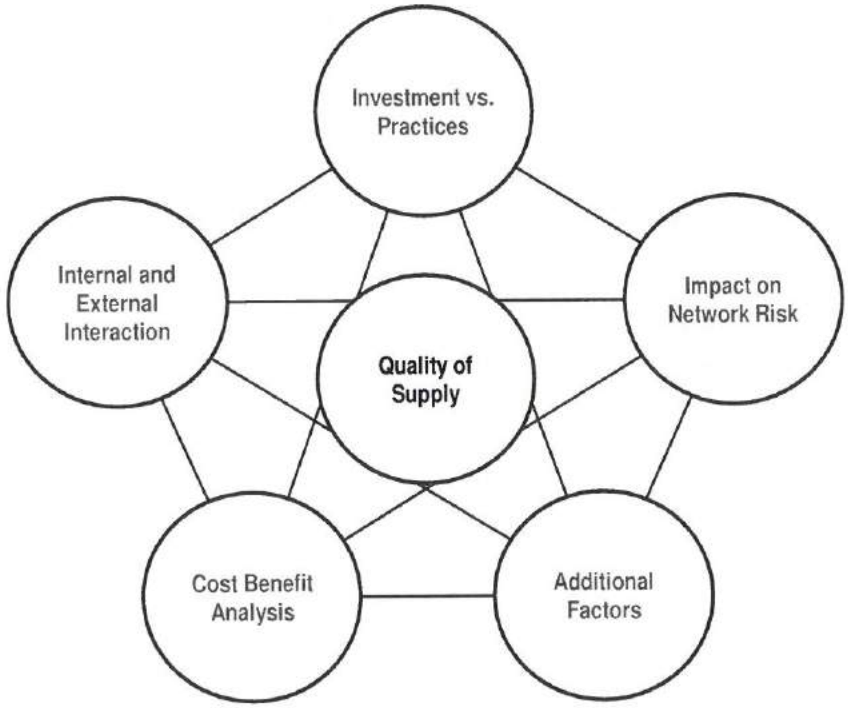


Table 8 Quality of Supply Investment Plan Development factors

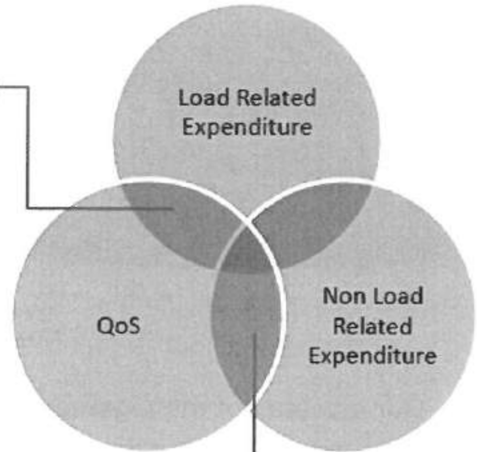
QoS investment plan development factors	Description
Internal and External Interaction	• Impact of Telecoms and IT on automation and automatic restoration of supply (internal) • Manage external interactions (see below)
Investment vs. Operational measures	• Impact of improvements from operational measures versus investment in network assets or other hardware/technology
Impact on Network Risk	• Assess the risk of outages as a consequence of deferred intervention • Assess the risk of increased probability of faults as a consequence of non-intervention • Assess mitigation actions if necessary
Additional Factors	• Suitability of Asset Health condition models in fast developing technology environment (e.g. SCADA) • Future technology serviceability • Impact of smart meters on data availability
Cost Benefit Analysis	• Whole Life Cost analysis • Incentive payments vs. investment cost

The result of the analysis above ensures that we expect to maintain or improve QoS in each of our networks and that we undertake the necessary interventions to meet our RIIO ED1 commitments.

As for the other investment streams, the development of QoS plans need to take into account the interactions with other plans.

Figure 10 QoS investment plan interaction with other streams

- Better network management through IT solutions that substitutes for additional LRE investment
- Network resilience and sectionalising impact on outages and consequently QoS
- Availability of adequate transfer capacity for automation to work



- Improve asset records to target maintenance
- Third Party interventions (e.g. vandalism)
- Fault frequency and impact (e.g. vegetation)
- Supply interruption for maintenance purposes (e.g. when cables need to be made dead due to congestion)
- Fault identification and remote restoration of supply
- Maintenance response intervention

5 Deriving NAMP through application of expert assessment

5.1 Our investment management team

Our Investment Management team is responsible for ensuring that the individual investment stream projects are coherently aggregated into our complete NAMP.

Further expert assessment and challenge is applied at this stage. This involves the application of sensitivity analyses, additional testing for deliverability and financeability constraints. This process ensures that the NAMP is thoroughly scrutinised and is resilient to known risks and the range of uncertainties that the network is exposed to (i.e. reflecting the uncertainty mechanisms in the regulatory framework).

As briefly touched upon in the previous chapters, expert assessment is applied throughout the NAMP development process in order to weigh up the range of competing drivers, objectives, and trade-offs of the options available to us.

Expert assessment ensures that the overall NAMP is:

- Compliant with the statutory obligations
- Efficient in delivering long-term value for money
- Robust when tested against different scenarios and risks
- Deliverable in terms of resources required
- Financeable

At NAMP level this translates into a number of optimisation goals as illustrated in Figure 11.

Figure 11 Optimisation goals under expert assessment

Table 9 Optimisation goals description

Optimisation goals	Description
Targeting optimum totex spend	• Ensuring the overall NAMP is in totality the efficiency sum of opex and capex (i.e. totex) that delivers the objectives and outputs, while recognising the long-term view and a need for flexibility to adapt to change
Smoothing for deliverability	• Reducing peaks and troughs in work programmes • Maintaining a smooth profile of work to avoid overstressing our workforce and supply chain • Aligning work packages from different streams into a coherent programme for the asset in question
Smoothing for financeability	• Reducing peaks in spend that would overstretch our financial standing
Aligning with our asset strategy and policy	• Ensuring the assumptions and modelled outcomes are aligned to our strategy and policy goals
Ensuring coherence with historical performance	• Achieving a plan that is based on assumptions inferred from the past and whose overall result is stress tested against experience
Addressing overlapping interventions	• Eliminating overlapping drivers or interventions from different investment streams • Optimising scheduled maintenance and other planned interventions

The approach to applying each of the optimisation goals is described below.

5.2 Alignment with our asset strategy and policy

Throughout the process we ensure that the optimised options chosen by our planners are consistent with the outcome committed in RIIO ED1 for each investment stream and at aggregate level.

Our asset strategy and policy frameworks provide some constraints on how discretion is applied in our expert assessment is made. This promotes consistency across the decision making process and ensures that discretion is exercised within specific boundaries. This alignment is ensured by our governance process and by the degree of challenge that takes place during the NAMP development process.

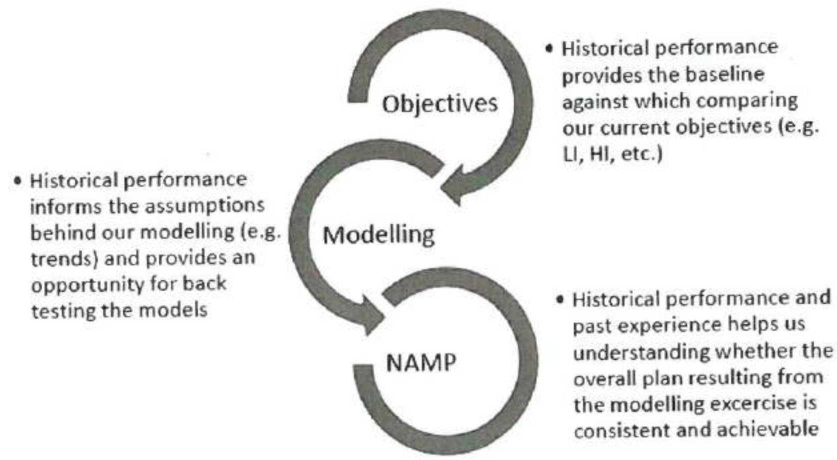
Further details on our overarching asset management policy can be found in AST 00 001 (Asset Management Policy). Individual lifecycle strategy documents outline instead the specific policy details for each asset class.

5.3 Ensuring coherence with historical performance

Throughout the process historical performance trends are used not only to derive model assumptions, but also to cross check the overall output of the NAMP to identify inconsistencies or step changes that emerge.

Figure 12 below illustrates how the assessment of historical performance is used in the NAMP development process.

Figure 12 Ensuring coherence with history in the NAMP development process



5.4 Addressing overlapping drivers of intervention

Overlapping needs for investment are a potential risk of the developing investment plans aligned to the drivers. These are most likely and significant in the following streams:

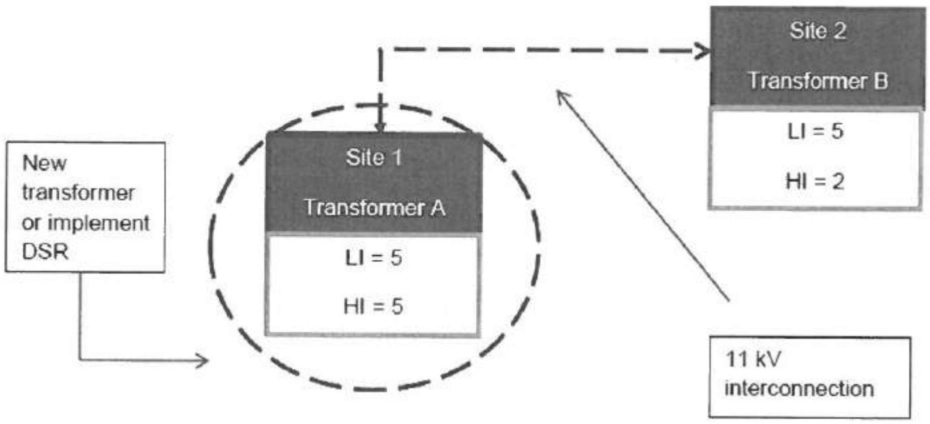
- Load Related Expenditure vs. Non Load Related Expenditure. Asset replacement models accurately indicate when a particular piece of equipment should be replaced / refurbished due to condition. On the other hand, local demand conditions or compliance requirements may indicate the need for the same asset to be upgraded to new standards or reinforced.

  This is illustrated below through a stylised example.

  Transformers A and B are closely located although they belong to two different circuits. Both transformers are rated as LI 5 categories and need reinforcement due to forecasted demand growth in 2018. In addition to that Transformer A is scheduled to be replaced / refurbished in 2015 as it is currently rated as an HI 5 asset.

  The first possible solution to the problem would be to refurbish transformer A in 2015 and increase the capacity of both transformers in 2018. On the other hand, savings could be achieved by moving forward the LRE investment for transformer A to 2015. In addition to that, planners would consider whether the expenditure for transformer B due in 2018, could be avoided by creating an 11 kV interconnection between the two circuits or by applying DSR measures until the HI of asset B increases to 4 / 5.

Figure 13 Addressing LRE vs. NLRE overlapping drivers



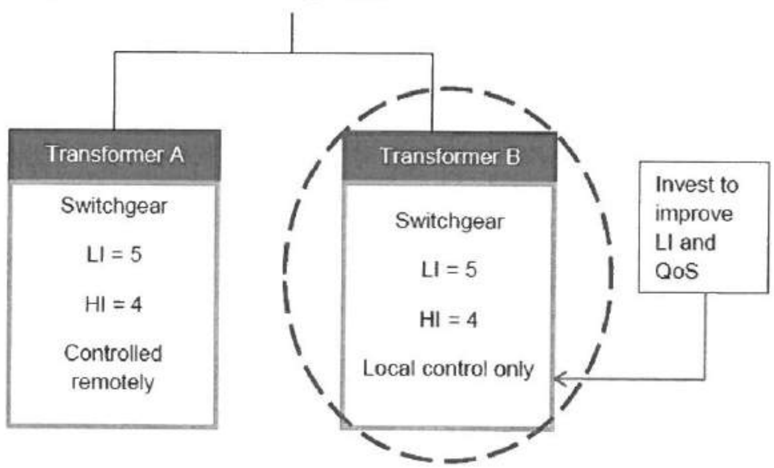
The teams in charge of Load Related Expenditure and Non-Load Related Expenditure investment streams are regularly in contact to ensure the plan is correctly optimised and to avoid duplications in the NAMP, both informally (e.g. through management) or formally through the Governance process (see chapters 6 and 76 & 7 for further details).

- Load Related vs. Quality of Supply. Automation will be a significant driver in improving the Quality of Supply performance of the network. On the other hand, a lack of load transfer capabilities imposes a limit to the benefits of such an option. The teams in charge of Quality of Supply and Load Related Expenditure ensure consistency between these two mutually dependent interventions.

  This is illustrated in Figure 14 below through a stylised example.

  Transformers A and B belong to the same circuit. Both Transformer switchgear assets have LI 5 (switchgear limited) and HI 4 indexes. At present only Transformer A switchgear can be controlled remotely. Presented with the choice of being able to replace only one asset, we would prefer to intervene on Transformer B switchgear as the project would have increased benefits to customers from the increased ability to reconnect customers quickly as the new switchgear would have remote control capability.

Figure 14 Addressing LRE vs. QoS overlapping drivers



The teams in charge of Load Related Expenditure and Quality of Supply Expenditure investment streams are regularly in contact to ensure the plan is correctly optimised and to avoid duplications in the NAMP, both informally (e.g. through management) or formally through the Governance process (see chapters 6 and 7 for further details).

- Load Related Expenditure vs. National Grid plans. Our models provide view of future reinforcement requirements for its Grid Supply Points. This forward-looking information is shared with National Grid (NG) through the "Week 28" submission and discussed in liaison meetings with NG. In developing the NAMP we seek to align future projects with the developments proposed by NG. This may lead to us or NGC rescheduling of our investments away from the optimised plan, which may in the case of a deferral require mitigating actions. This may lead to a less efficient plan for us, but an overall benefit (from lower transmission costs) to customers who pay both transmission and distribution charges.

The following is a real example of managing duplications:

The replacement of the Barking to Brunswick Wharf 132kV gas cable circuit in the London Power Networks with a solid cable is an example where expert assessment was used to test divergent modelling outputs.

The above mentioned cable circuit requires replacement due to condition but also reinforcement for P2/6 compliance purposes.

Whilst it was desirable to schedule the replacement of the circuit later in the middle of ED1 from a condition and smoother NAMP perspective, P2/6 compliance considerations led the planners to shift the intervention earlier in the regulatory period.

The decisions discussed above and supporting information is recorded in our Regional Development Plans.

5.5 Targeting optimum totex spend

Expert assessment is applied to ensure that the NAMP is consistent with efficient capex / opex trade-offs. These trade-offs are particularly important as they influence how the cost of operating the network is apportioned between current and future customers.

For instance, Load Related Expenditure (Reinforcement) vs. Non Load Related Expenditure (Demand Side Response) decisions are subject to different capex and opex expenditures which in turn produce different level of totex expenditure profiles over time. In deciding the right option for customers, we look at minimising the costs to customers of our plans by using Whole Life Cost models and examining the profile expenditure over time to minimise volatility.

The NAMP development process is designed to ensure that the overall totex expenditure is optimal and delivers our strategic objectives, outputs, in the interests of both current and future customers - recognising the future is uncertain.

The NAMP is a key input to our business' financial health. The impact of the NAMP is tested by Strategy and Regulation / Business planning as part of the overall testing of our plans for financeability. For more information on how the plan is developed with input and challenge with internal stakeholders please refer to chapter 7.

Ensuring optimum totex

UK Power Networks has a constrained substation in the East London area; Whiston Road 11 kV. The Whiston Road 11 kV substation needs to be upgraded to accommodate the load growth in the area. Unfortunately there is not enough space at the substation for the upgrade to take place and therefore a new substation will need to be built and the load transferred. The new substation is proposed to be built in nearby Hoxton.

Demand Side Response (DSR) solutions have been investigated at the site. Using DSR will enable UK Power Networks to defer the build of the new Hoxton substation out of RIIO ED1 and help manage the network constraint at Whiston Road 11 kV substation. Contracting 5 MVA DSR between 2021 and 2025 (inclusive) will defer the new Hoxton substation thus creating considerable benefits.

5.6 Smoothing for deliverability

The delivery of the NAMP requires a strategy that does not to overstretch the finite resources available (e.g. skilled contractors) and to ensure minimum service disruption.

Smoothing for deliverability is therefore one of our optimisation goals. This is routinely undertaken for each individual investment stream. The most frequent types of actions undertaken are:

- Stagger or reschedule investment. Specific asset conditions (for instance age profile) could lead to a significant volume of work at discrete points in time. In turn, this could create deliverability pressures (for instance on the supply chain). The teams within each individual asset streams, apply expert assessment to stagger or delay specific type of investments / interventions. This type of decisions is taken based on industry best practice or experience of dealing with specific assets and it is constantly reviewed and challenged by senior management to ensure that the overall network risk remains broadly constant
- Long-term view. We look at the portfolio of projects that are proposed for a region and consider whether mix of solutions provide suitable flexibility. Flexibility will be considered around issues including system access, potential variation from the core scenario view and operational complexity. For example, sequencing of projects in a region could lead to complicated and multiple outages for customers to allow new capacity to absorbing delivery resources and slowing the provision of new capacity
- Contract additional resources. In certain instances contracting additional resources is the only option available when a significant and prolonged type of intervention is required. The teams within individual asset streams and Delivery functions proactively look into future requirements to assess the adequacy of the available resources

The NAMP is further tested for deliverability. This process occurs within the specific process and Governance measures described in chapter 6.

5.7 Smoothing for financeability

Investment plans have a significant impact on our financial performance due to their size and profile. This in turn impacts our overall financeability.

We work with the business planning team to review the individual and aggregate NAMP streams of expenditure to ensure it allows us to work within our financial constraints. Adjustments are made by seeking to staggering investments whenever feasible or by ensuring maximum alignment between investment plans and the available financial capacity.

Under ESQCR Risk mitigation programme, the planning for structural mitigation could be expensive as possible mitigations include diversion/undergrounding. This type of work has been staggered by smoothing the expenditure and work over the next 10 years. This has reduced the increased expenditure requirement in the initial years and have smoothened the expenditure profile over the ED1 period.

6 Governance

Each step of the process described above is undertaken within strict governance rules and processes. This ensures that the NAMP is:

- Challenged by the relevant decision makers
- Change controlled
- Rigorously risk assessed
- Appropriately documented
- Properly communicated
- Effectively implemented

Specifically, the individual NAMP projects are scrutinised at:

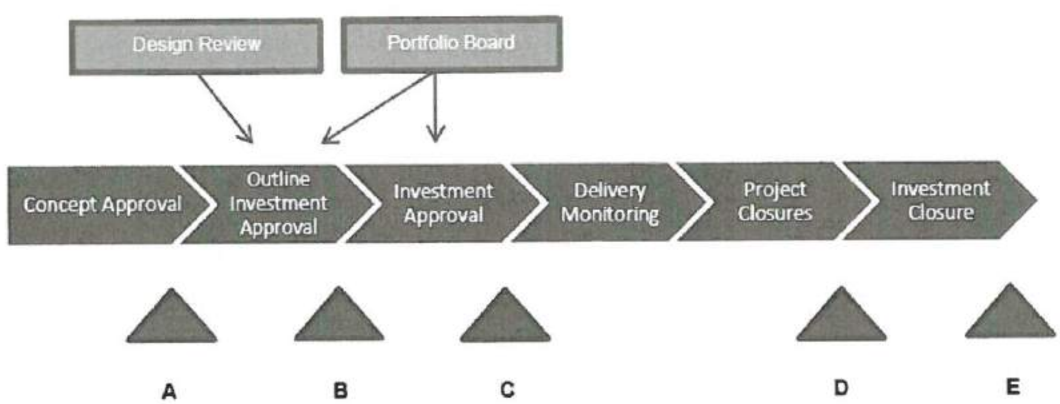
- Design Review.
  This consists of fortnightly weekly meetings chaired by a senior manager within the Asset Management function during which the initial project concept is scrutinised from an engineering perspective. Attendees include representatives from Connections, Capital Programme Delivery, Capital Programme & Procurement and Network Operations (Control).
- Investment Portfolio Board.
  This consists of weekly meetings, chaired by the Director of Asset Management (or his delegated deputy) to review plans, relevant documentation and commercial decisions where approval for capital expenditure greater than £1m is sought.

Each of the NAMP investment projects that require capital expenditure is subject to the "Regulated Project Approval Process" (EDP 08-0801). The framework details the approval authorities, roles, responsibilities and procedures that need to be adhered to when approving capital expenditure for regulated projects.

Project approval occurs twice within the overall "Regulated Project Approval Process", first at the Outline Investment Approval stage and second at the Investment Approval Stage.

Figure 15 provides an overview of the "Regulated Project Approval Process" with relative Gateways (A to E).

Figure 15 Project Investment Gateway process



Each Stage / Gate within the process is further described in Table 10 below.

Table 10 Regulated Project Approval Process stage / gate description

Stage	Gate	Description
Concept Approval	A	This is the point at which an opportunity or business need is first identified, and approval of the concept in principal is sought prior to proceeding to the next Gate.
Outline Investment Approval	B	This is the point at which approval of the preferred option is sought prior to proceeding to the next Gate. Generally for Major NAMP projects this is the point where all the options have been considered and the Planners hand over their preferred solution to the Delivery Team for development into the full investment form.
Investment Approval	C	This is the point at which the preferred solution is identified in detail. Also, this is when the capital expenditure values for NAMP Projects are approved.
Delivery Monitoring		This is the stage in which the project is monitored to ensure efficient delivery.
Project Closures	D	This is the point at which the project is complete and a review is carried out to assess its success in order to identify best practice and capture the lessons learned and closing out SAP.
Investment Closure	E	This is the point at which the Investment is closed and the benefits, if any, stated in the Investment form, are measured.

Further details on the overall NAMP development roles and responsibilities can be found in Document EDP 08-0300 (NAMP Development Process Overview), whilst document EDP 08-0301 deals with the overall NAMP Change Control Process.

7 Stakeholder management

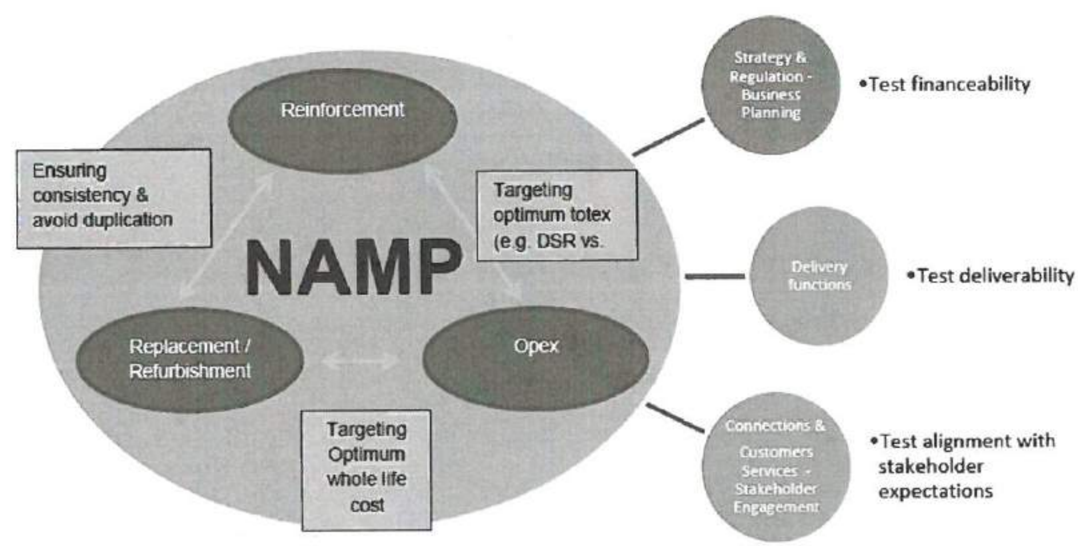
Each step of the process described above has also been informed by extensive stakeholder engagement both internally and externally.

Figure 16 below provides a schematic diagram of how the stakeholder engagement has influenced the development of the NAMP:

The key actors that constantly interact to deliver the NAMP are:

- The Asset Management teams (e.g. Asset Management, Investment Management, Asset Strategy, System Development, etc.)
- The Strategy and Regulation / Business Planning teams
- The Delivery functions – Network Operations and Capital Programme and Procurement
- Connections
- Customer Services, external Stakeholder Engagement teams

Figure 16 Stakeholder engagement for the NAMP development process



The Asset Management teams are responsible for developing the NAMP. In particular, they ensure that the interactions between the key investment streams of reinforcement projects, replacement interventions and direct operating costs are fully understood and addressed.

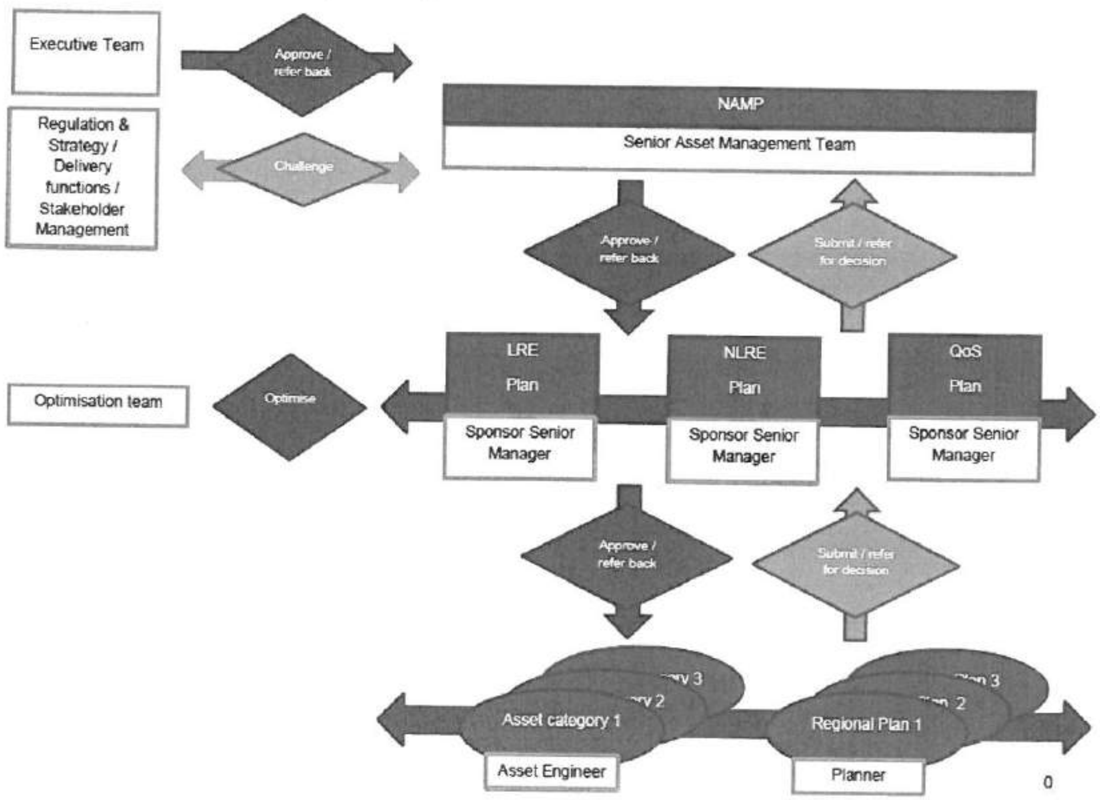
They work to reflect our customers' desired outcomes, based on the work by our Customer Services - Stakeholders Engagement team in collecting these insights, fulfilling the businesses broader objectives and remaining with the finite resources available.

The process is run dynamically, recognising that new information and delivery challenges may impact on the delivery of the plan and change priorities. This means that there is continuous process of dialogue where the Asset Management teams interact with each other and other internal stakeholders on a regular basis. This occurs formally as a part of the Governance framework (e.g. Portfolio Boards, Gateway process, etc.) and through informal basis of good management practice (e.g. managerial approval, meetings with interested parties outside the scope of the Governance framework) as illustrated in Figure 17.

A key internal stakeholder, are the Delivery functions. They are continuously involved in assessing the profile of future interventions on the network so to ensure that the NAMP can be realised within any existing resource and delivery constraints (e.g. skilled resources, supply chain, etc.).

The overall alignment with the business objectives, ED1 commitments and stakeholder feedback is carried out as part of the wider business plan process that delivers a well-justified plan.

Figure 17 Building the NAMP dynamically



8 Conclusion

UK Power Networks development of the Network Asset Management Plan is based on a robust process as summarised in this document.

In-depth descriptions of our Stakeholder engagement process used to inform, shape and scrutinise the plans is available.

A review of our leading industry modelling techniques is provided in detail in other Annex documents.

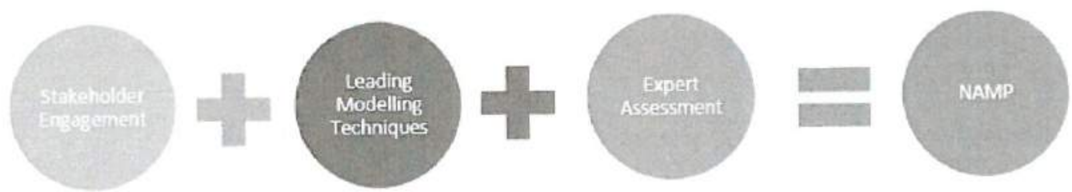
You can find more detail around our planning processes in the following documents:

Table 11

Document number	Title
AST 00 001	Asset Management Policy
EDP 08-0106	Production of Annual Planning Load Estimates (PLE)
EDP 08-0300	NAMP Development Process
EDP 08-0301	NAMP Change Control Process
EDP 08-0600	Network Design Review
EDP 08-0801	Regulated Project Approval Process

Finally, the output of the NAMP development process for our direct expenditure for each investment stream and asset class for each network is described in the annex documents within the Business Plan submission.

Figure 18 Main features of the NAMP development process



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(27)

MANITOBA	Board Order 116/08
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 29, 2008
Edited for format and typographical errors only August 25, 2008 Further amended September 4, 2008	

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS

128

Despite prior cautions from the Board, MH intends to spend, on average, $385 million a year on capital construction through to and including 2017/18, capital expenditures that are not related to major generation and transmission projects, which are accounted for separately. In an effort to better justify and demonstrate the necessity of such normal capital expenditures, the Board agrees with interveners on the need for a periodic Asset Condition Assessment Study.

The Board agrees that a study of this nature, done at reasonable intervals, will assist in evaluating MH's progress in maintaining the electrical system, and should also provide additional support for the level of OM&A being incurred and forecast. The Board believes it's appropriate that MH undertake such a study, and will so direct MH to undertake and file with the Board an Asset Condition Assessment by June 30, 2009, that defines:

a) major assets and categories of assets;
b) the estimated remaining economic life of each major asset and category of asset;
c) an indication of the implications for OM&A costs related to maintaining required and scheduled maintenance;
d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;
e) forecast expenditures for planned renovations and/or replacements with respect to now-available energy supply and transmission; and
f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH is to file with the Board detailed Terms of Reference containing the scope for

In terms of Wuskwatim, the Coalition noted that the development is placing pressure on MH's debt to equity ratio and on its revenue requirement. In addition, the Coalition noted that the intended closure of the Brandon Coal plant (that is except, for emergency use) is another important impact arising from provincial involvement in MH decision-making. The Coalition stated that MH is experiencing significant pressures on its financial results from a variety of government policy and other initiatives, though many of them have, in the past, been beneficial to Manitobans.

Mr. Harper noted that MH's capital spending for the two closest forecast years, 2007/08 and 2008/09, is to be considerably higher than historic levels, mainly due to higher spending on new generation and transmission. Mr. Harper stated the spending is in part to protect in-service dates and is being done to meet export commitments and goals, and that this spending is putting noticeable pressure on MH's debt to equity ratio.

As of fiscal 2006/07, Mr. Harper opined the impact of spending on major new generation and transmission projects has increased the debt ratio by 2 percentage points. And, by fiscal 2008/09, increased capital spending will drive up the debt ratio by 5 percentage points.

Mr. Harper submitted that in the near term, Wuskwatim will have the most impact on the change in outlook for capital spending, due both to cost increases and as a result of the advancement of the in-service date. The Coalition observed that MH's capital spending plans influence decisions about the level of net income and the level of rate increases.

As previously mentioned, Mr. Harper argued for a direction to Hydro to develop an ACA and described an ACA as a snapshot of the condition of a utility's assets, noting that it would include degree of degradation and need for rehabilitation and replacement. He suggested that ACA are usually undertaken at intervals of two to three years.

Mr. Harper claimed that an ACA helps a utility pull together, on a systematic and organized basis, an overall comprehensive assessment (for planning purposes) of work to be prioritized across its entire asset base. And, through a process of prioritizing assets by way of an ACA, MH can further prioritize work in areas of the company where there is a deficiency of a critical nature. Mr Harper stated an ACA provides a logical foundation to support OM&A and capital spending

Mr. Harper further recommended that MH undertake regular ACAs every 2 to 3 years, and that the preparation of such assessments over time will allow MH to determine whether its assets are improving or deteriorating, helping to substantiate where there is a need for increased spending.

Mr. Harper noted that MH's capital spending requirements for both base capital and new generation and transmission projects are growing, when compared with past spending levels. He indicated that while increased export revenues should benefit future customers, the capital expenditures to prepare for those exports are putting pressure on current rates and are one of the drivers for MH's requested rate increases (that now exceed inflation). For Mr. Harper, MH needs to be mindful of these pressures when developing its overall capital expenditure plans.

Mr. Harper opined that the advancement of Wuskwatim was a contributing factor to current rate pressures. In reaching this conclusion, Mr. Harper noted that a significant portion of the increases in capital spending to be experienced in the next few years relate to the development of Wuskwatim.

8

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO'S APPLICATION
FOR APPROVAL OF NEW ELECTRICITY RATES
FOR 2010/11 AND 2011/12

Before Board Panel:
Graham Lane - Board Chairman
Robert Mayer, Q.C. - Board Member

HELD AT:
Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
July 4, 2011
Pages 8328 to 8524

and very important and we thank the Board for that.

Turning to page 58 of the outline and skipping right over page 57. Our clients point the Board at the top of page 58 to the Boar -- to Hydro's response to CAC/MSOS Information Request 17C. And because we asked it to explain how it determines maintenance and replacement requirements. And this response was very telling from our client's perspe -- perspective because the response deals with each functional area separately and talks about the tools and processes used by each area to determine its individual needs. And while there is a discussion under each area of prioritization, there is no real indication of how that prioritization is done. No assurance that the same values and objectives are used by each business unit.

And based on our reading of that response we find it difficult to conclude that there is a process for prioritizing projects across the various functions. Again, we may be incorrect in that presumption or conclusion but that was our reading in 2008, it remains our concern today.

Directing your attention to the bottom of page 58 under the heading "Issues and Recommendations." It's important and contextually important to understand that asset management plans are increasingly used by

9

MANITOBA	**Board Order 5/12**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**January 17, 2012**

Before: Graham Lane CA, Chairman
Robert Mayer Q.C., Vice-Chair

A FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

- Thermal Generation Facilities:
  - Steam plants - 65 years life. MH's ongoing investments in the Brandon and Selkirk plants may not support the notion of a 65 year life.
  - Natural gas combustion turbine - 25 years life. Some questions of the true economic value of these plants remain.
- Transmission Lines:
  - Towers - 75 to 85 years life. Events on Bipoles I and II in 1996 and 2011 suggest remediation of failed or damaged facilities could reduce the effective life cycles.
  - Conductors - 60 years life. Aside from the former Winnipeg Hydro transmission upgrades, MH has indicated a need for early replacements.
- HVDC Converter Stations:
  - Structures - 57 years life. No indication of problems exists.
  - Serialized equipment - 37-43 years life. Indications from prior evaluations are that the serialized equipment (synchronous condensers) may need replacement in 20 to 50 years.

10.3.0 BOARD FINDINGS

Depreciation (amortization) expense is forecast in this application based on an out-dated 2005 depreciation study. The Board is aware that a result of IFRS requirements for componentization will likely lead to an increase in depreciation expense, as components will have to be carved out and depreciated over their respective shorter service lives rather than over a longer service life of the asset as a whole. The Board understands that a new depreciation study is being prepared.

The Board remains concerned that an Asset Condition Assessment Study has been delayed and notes that several of the assets, which are being depreciated over long periods of time, may require major repairs in the interim.

There does not appear to be any explicit recognition of the physical condition and ongoing repairs associated with the individual generating stations or transmission facilities. This suggests that MH may not have an adequate history of physical plant conditions and rehabilitation needs such as would be included in an "Asset Condition Assessment". The Board will require MH to file an Asset Condition Assessment and depreciation study at the next GRA.

10

143

MANITOBA	**Order No. 116/12**
THE PUBLIC UTILITIES BOARD ACT	
	August 29, 2012

BEFORE: Régis Gosselin, CGA, MBA, Chair
Raymond Lafond, BA, CMA, FCA, Member
Larry Soldier, Member

AN INTERIM MANITOBA HYDRO RATE ORDER
EFFECTIVE SEPTEMBER 1, 2012

persons as to their position on MH's September 1, 2012 interim rate requests. This written submission process was part of the general hearing notice published by MH.

The Board conducted a Pre-Hearing Conference on July 26, 2012 to consider which Interveners should be approved for participation in the GRA public process, to consider the scope of the GRA and to consider the timetable for the orderly exchange of evidence leading to a public oral hearing in late 2012. Intervener status was granted to Manitoba Industrial Power Users Group (MIPUG), Consumers Association of Canada (Manitoba) Inc. (CAC), Green Action Centre (GAC), The City of Winnipeg (City) and Manitoba Keewatinowi Okimakanak (MKO).

Given the timing of the GRA filing in mid-June 2012 and the timetable to complete the full hearing process, it is not anticipated that a final rate Order will be approved by the Board until sometime in 2013.

As part of the September 1st interim rate application process the Board considered the initial GRA evidence and further supplementary GRA materials filed by MH along with MH's written submission in support of the interim rate requests. The Board also considered the written submissions of MIPUG, CAC, and GAC and the written reply submission of MH. City and MKO did not participate.

The Board has benefited from the submissions of MH and all participating interveners as to the principles to be reviewed and the merits of a 2.5% September 1, 2012 interim rate increase. No submissions were received respecting the merits of the 6.5% diesel zone increase also to be implemented September 1, 2012 affecting General Service and Government classes.

4.0.0 MANITOBA HYDRO'S SUBMISSIONS

MH seeks interim approval for the proposed rate changes effective September 1, 2012 for the following reasons:

145

1. The need is urgent to avoid continuing losses on operations as will be evidenced in the Quarterly Report of the Manitoba-Electric Board for the three months ended June 30, 2012, which was to be released on or about August 15, 2012 (a by-election has held up release of the quarterly report);

2. Financial Ratios are deteriorating and are projected to further deteriorate in the test years;

3. It is essential that the financial and credit rating integrity of Manitoba Hydro be maintained;

4. Prices on the export market are not expected to improve substantially in the near term;

5. Costs are being well controlled and cannot be reduced further without negatively impacting the safety, reliability and efficiency of the power system;

6. The aging infrastructure issue will result in higher maintenance and capital costs in the future;

7. There is a separate government-approved process to review Manitoba Hydro's major capital projects; in the meantime, current rates do not include any costs related to capital projects before those projects are placed in service; and,

8. Even with the proposed rate changes, electricity consumers in Manitoba will continue to benefit from the lowest electricity rate structure in Canada.

If MH receives the increases it seeks, it currently projects that net income from electricity operations will be approximately $60 million for the year ended March 31, 2012, which is $79 million less than the net income for the previous year.

Moreover, MH now reports that its financial position has deteriorated significantly since the conclusion of the 2010/11 and 2011/12 GRA proceeding. Projected net income and report for the three month period ended June 30, 2012, MH reports that it has suffered a substantial net loss on electricity operations in the first quarter of 2012/13.

The Board has real concerns about the deteriorating financial position of MH and the negative turn in the financial ratios that will follow based on the projections filed by MH if the requested interim increases are not granted.

The Board appreciates that MH's revenues and expenses have not been tested and that the GRA process, now underway, will afford the Board and Interveners the opportunity to do so. However, given MH's current circumstances, it is arguable that if MH's case is borne out and the interim increase is not approved, much larger (and therefore less gradual) rate increases than originally planned will be required in 2013/14 since MH will not have recovered these revenues in the upcoming winter heating period while the GRA process unfolds leading to a final rate Order. The Board, as it has previously stated, disapproves of retroactive rate increases.

In accepting the financial projections filed by MH at this time, the Board does not make any binding conclusions as to the particular aspects of the financial details challenged by the Interveners and which have been addressed in detail by MH in its reply submission. It does not appear that there has been a material improvement to MH's net income position since the Board granted the 2% interim increase effective April 1, 2012. Moreover, there was limited time available for the Board to make its ruling leading to the April 1st rate Order. The Board has considered this Application based on all of the subsequent materials provided by MH.

CAC has highlighted the limited evidence currently available to support MH's assertion of curtailment of capital spending on all but essential elements of its operations to meet safe and reliable service standards, and has identified certain issues regarding OM&A expenditures and analysis by MH that should be examined further. MH will be expected to demonstrate the internal savings that the Corporation has realized in an effort to reduce expenses and improve net income. A portion of the quotation from the Moody's

11

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

GENERAL RATE APPLICATION

2012/13 AND 2013/14

Before Board Panel:

Regis Gosselin	- Board Chairman
Raymond Lafond	- Board Member
Larry Soldier	- Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

February 25, 2013

Pages 5689 to 6003

context in which Manitoba Hydro has used it in this hearing.

And certainly, the question comes to our client, given the situation of Manitoba Hydro, the question that they pose at page 7 is: Is this fait accompli? Should we resign ourselves to dramatic rate increases? Is this the season of darkness in the winter of despair for Manitoba ratepayers?

And really, the answer to that depends on -- on a tale of two (2) Hydros and which version of that tale you accept. Is Manitoba Hydro merely a victim of unfortunate circumstances? Or has Manitoba Hydro played a role, a meaningful role, in authoring its own situation?

So tale 1 and the -- the faultless Hydro appears on page 8. It's a story of Shale Gas and its impact upon export revenues and export demand. It's a story presented by Mr. Warden, certainly in this hearing, of capital expenditure situations beyond the control of Manitoba Hydro; sticker shock, sticker shock. It's a story of the US recession. Those are really the big three (3) of the faultless Manitoba Hydro, and that's certainly a story that it has ably presented in this hearing.

But there's a different tale, as set out in page 9, and that's the tale that our clients endorse. And that's a tale of a Manitoba Hydro which has been buffeted by untoward circumstances, certainly in terms of the export market, but a Manitoba Hydro that has a lot of work to do to sharpen its pencil to -- to get its act in order.

And this is a Manitoba Hydro, as we note on page 9, that in our client's respectful submission, is staying behind the curve in asset management best practice. It was out of date, in our client's perspective, in 2008. It's made some strides, but it's still behind the curve even now.

It's a Manitoba Hydro that's swimming against the tide, the North American tide, in dramatically reducing incremental DSM savings. It's a Manitoba Hydro that's incurring dramatic -- that incurred dramatic increases in Wuskwatim's capital expenditures, including a 13 percent increase post, flowing from the capital expenditure forecast 2009, so after sticker shock presumably would have susided -- subsided with the great recession of 2008.

It's a Manitoba Hydro that, in our client's submission, has -- has had some shortcomings in its management of the diesel program, difficult as that program may be. And a Manitoba Hydro that has submission, in our client's respectful view, both Manito -- both the Manitoba Public Utilities Board and certainly our client, in those proceedings known as the Coalition, were -- were urging Manitoba Hydro to get their capital asset management program in order.

They were warning Manitoba Hydro that their Low Income Energy Program would not succeed as currently designed. They were urging Manitoba Hydro to get their day-to-day expenditures under control. And this Board in particular was warning Manitoba Hydro that their capital programs entailed more risk than Manitoba Hydro envisioned or was portraying.

So at page 17, our clients begin an extensive discussion of asset management. And on page 17 -- and I'm not going to, I'm sure you'll be relieved, walk you through that extensive quote. It's from the KEMA report, which is actually now four (4) years old. But KEMA, which was a re -- which is a ref -- an exhibit on this record, CA-13 -- CAC (Manitoba)-13, is a compilation of asset management best practice and principles compiled for the purposes of the Ontario Energy Mor -- Board.

And KEMA makes the point that asset management is essential, but it's not new. This issue is not something that was discovered in 2008. Indeed, in the United Kingdom, utilities have been working on it for ten (10) to fifteen (15) years. And certainly in Canada, it was not a novel discovery in 2008.

But the thrust of the increased emphasis over the last ten (10) to fifteen (15) years on asset management does echo a concern of Manitoba Hydro, that we're in a period of a -- where infrastructure is getting older. And at this point in time in particular, it's important to optimize asset replacement in order to minimize future operating costs.

And so we put in, on pages 17 and 18, some selections from KEMA, making the point of how important asset management is, in terms of allowing modern corporations to make prudent and reasonable decisions. And at the bottom of page 18, you'll see a reference to the fact that of course this is not new, it's been going on in the United Kingdom for quite some time.

And on the record of this hearing, Mr. Chairman and Members of the Panel, is the first efforts by Manitoba Hydro in terms of a compellation of an asset condition report. And we thought at page 19 it was important to distinguish between what is an asset -- I see I've spelled 'assessment report' improperly on the large bullet -- but the difference between an asset condition assessment as -- as compared to a management plan.

With the asset condition assessment being a review, a state of the union, when it comes to the corporation's components in terms of their relative health, in terms of the cost associated with repair and the urgency of those repairs. But it's just one (1) stepping stone to what should be and has to be an asset management report and strategic plan allowing a corporation to develop a multi-year plan to maintain its assets and -- and prioritize properly.

And at page 20, we simply note, you've heard evidence from Manitoba Hydro, Mr. Warden in particular, in this hearing that doing these asset management assessments and these plans is complicated, because their business is complicated. And our clients accept that.

But the point our clients wish to make at -- at page 20 is not only were folks in the United Kingdom getting on the road of proper asset management assessment and management, but so were folks in Ontario. So were folks in different parts of Canada. And certainly way back in 2008, we had very refined asset management plans from Ontario to share with

Manitoba Hydro. So the point we make at page 20 is that Manitoba Hydro then was behind the curve.

And at page 21, really we set out our client's concerns with the state of the union where Manitoba Hydro was on this critical issue back in 2008. And our client's view at that point in time, it was behind the curve, in terms of good practice and reporting as compared to other jurisdictions.

And frankly from our client's perspective and certainly the expert witness presented by Manitoba -- by Mr. Harper on behalf of the coalition on that point in time, its practices appeared relatively simplistic compared to our client's experience or our expert's experience in other jurisdictions. And certainly back in 2008, our clients were not confident that Hydro was managing its day-to-day capital investment in a way to optimize ratepayer value and quality.

The last point in terms, you can read the rest of the page at your leisure, we're also -- as we turn to page 22, Mr. Harper -- so on the next page, Mr. Harper also flags and our client flagged another concern. How was this regulator to sit in judgement on the prudence and reasonableness of Manitoba Hydro's expenditures when it didn't have a asset management assessment or asset condition assessment and a asset manage -- asset management plan to properly review?

At page 23 our clients provide an excerpt from the Board order relating to -- to asset management to -- to suggest to you that our concern was not restricted to the coalition, but it was shared by the Board. I would caution when the Board looks at this excerpt, there's a date there of June 30th, 2009. And of course, that date was sub -- subsequently varied.

So we simply include this quote just to highlight the fact that this matter, not only was of -- of significant concern to the coalition, but it was of significant concern to the PUB almost five (5) years ago now.

So at page 24 we ask the question: Where is asset management in 2013? And the conclusion we draw, aided by the evidence of Manitoba Hydro, is that the Corporation is still not there yet in terms of where it should be, in our client's respectful submission.

And we've given you some quotes, in terms of excerpts from the record. At the top of page 24, we're still not there, in terms of having something that we can say we're total -- totally satisfied with energized." You know when he talked about how daunting the task was originally but now, We're moving along really well and we're excited about how it's going. And he really -- I believe it was in a response to questions by Board member Solider, he says,

> "You know, even with poles and cables, there's like different views on prioritization."

And -- and he pointed to the value, instead of thirty (30) different or twenty (20) different areas creating their own priorities, getting a centralized approach, bringing in best practices, improving productivity. And it's a fabulous quote on pages 3,853 and 3,854 which certainly our client urges upon the Board, because it's really a testimony -- a testimonial, A) to the potential, but also insight into the -- the need for this and the need, which, in our client's submission, should have been bef -- implemented many years before.

So in terms of asset management practices, Mr. Chairman and members of the Board, is it the best of times? Is it the worst of times? It's better than 2008. But certainly in our client's view, Manitoba Hydro even in 2008 was half a decade behind the curve at least. So it's better but it's -- it's

12

161

MANITOBA

THE PUBLIC UTILITIES BOARD ACT

Order No. 49/14

May 6, 2014

Before: Régis Gosselin, B és Arts, M.B.A., C.G.A., Chair
Marilyn Kapitany, B.Sc. (Hons), M.Sc., Member,
Larry Soldier, Member

INTERIM ORDER IN RESPECT OF MANITOBA HYDRO'S APPLICATION FOR INTERIM ELECTRICITY RATES EFFECTIVE MAY 1, 2014

3.0 Intervener Submissions

Consumers' Association of Canada (Manitoba) Inc. (CAC)

The Consumers' Association of Canada (Manitoba) Inc. (CAC) opposes Manitoba Hydro's requested rate increase and considers it to be materially inflated in light of evidence that Manitoba Hydro could meet its 2014/15 financial targets without any rate increase. CAC submits that an interim rate increase should be limited to the rate of inflation. It states that Integrated Financial Forecast IFF-13 shows a forecast net income for electric operations of $116 million, which compares to only $78 million the previous year. CAC further cites several factors to suggest that actual net income for the 2013/14 fiscal year will likely be higher than projected in IFF-13.

CAC submits that Manitoba Hydro has not implemented cost control measures that would limit Operation, Maintenance & Administration (OM&A) expenditure growth to 1% per year, and only plans to do so starting in 2015/16. In CAC's view, implementing such cost constraint measures now would decrease projected OM&A costs in 2014/15 by $5 million.

CAC further states that there are several outstanding directives from Board Order 43/13 relating to the transition to International Financial Reporting Standards (IFRS), and that Manitoba Hydro has not yet performed an Asset Condition Assessment for its Generation and Transmission units.

In CAC's view, Manitoba Hydro is basing its request for a 3.95% rate increase on its planned implementation of the Preferred Development Plan, which has been challenged in the current NFAT review and may no longer be the best option.

Lastly, CAC expresses concern about Manitoba Hydro's stated intention to file a three-year General Rate Application in the fall, and suggests that any application should be limited to two years at most.

163

billon. Once Bipole III will come into service (in 2018) it will affect Manitoba Hydro's Operating Statement. In Board Order 43/13, the Board determined that Bipole III will require additional annual revenue requirements of approximately $300 million when put into service, and which yearly amounts will have to be recovered in domestic customers' rates. As part of the last General Rate Application, the Board in Order 43/13, required Manitoba Hydro to establish a deferral account into which the proceeds of a 1.5% rate increase were to be deposited to defray a portion of the rate impacts of Bipole III. This deferral account continues to be active, and the Board remains concerned with the revenue requirement impact that Bipole III will have. Accordingly, in addition to the 2.00% interim rate increase approved above, the Board will approve an additional 0.75% interim rate increase to existing rates, the proceeds of which are to be collected in the Bipole III deferral account established in Order 43/13.

Depreciation & Amortization

As noted by CAC, Manitoba Hydro has not yet filed an Asset Condition Assessment that would provide additional clarity regarding expected depreciation and amortization expenses in the future. Directive 7 of Order 43/13 required Manitoba Hydro to file an Asset Condition Assessment no later than the filing of the Corporation's next depreciation study.

OM&A Increases

The Board has expressed concern with the growth of OM&A expense in prior Orders and remains concerned with Manitoba Hydro's increases in OM&A spending to date, as stated in Order 43/13. Manitoba Hydro's most recently filed financial information shows that since Order 43/13 was issued, OM&A costs have continued to escalate. While Manitoba Hydro has stated that it targets below-inflation growth in OM&A expenses of 1.0%/yr in 2015/16 and expects OM&A expense to grow by only 1.3% in 2014/15, the Board notes that to date, Manitoba Hydro has not been able to achieve below-inflation

165

13

M A N I T O B A	)	**Order No. 73/15**
	)	
THE PUBLIC UTILITIES BOARD ACT	)	**July 24, 2015**

BEFORE: Régis Gosselin, B ès Arts, MBA, CPA, CGA, Chair
Richard Bel, B.A.,M.A.,M.Sc., Member
Hugh Grant, Ph.D., Member
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Member

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2014/15 and 2015/16 GENERAL RATE APPLICATION

be able to fund such expenditures from cash flow. However, Manitoba Hydro states that in the absence of the proposed rate increases, Manitoba Hydro would be required to fund an increasing portion of its sustaining capital expenditures through debt financing as opposed to cash flow generated from operations. These rate increases reduce the need for borrowing and additional financing costs that must be borne by customers through rates.

Despite the fact that sustaining capital expenditures replace existing assets, any such investments are fully capitalized, which means they are depreciated over the expected life of the new asset. As such, the incremental effect on revenue requirement of the $100 million spending increase during 2015/16 is only approximately $4 million, and sustaining capital is not a significant driver of the 2015/16 rate increase.

Manitoba Hydro established the following sustaining capital expenditure budgets to 2020:

- $132 million per year for seven years for generation projects;
- $125 million per year for six years for transmission projects; and
- At least $206 million per year for six years for distribution projects.

In its prior capital expenditure forecasts (e.g. CEF-08), Manitoba Hydro provided details of individual capital projects over $1 million. Now, Manitoba Hydro provides a top-down budget for each of generation, transmission, and distribution and separately identifies only projects over $50 million. As a result, the number of specific projects identified in the CEF decreased from 98 in CEF-08 to 11 in CEF-14.

Manitoba Hydro's Asset Condition Assessment Process

In Board Order 116/08, the Board directed Manitoba Hydro to prepare an Asset Condition Assessment Report that set out the following:

(a) major assets and categories of assets;

169

(b) the estimated remaining economic life of each major asset and category of asset;

(c) an indication of the implications for operation, maintenance & administration (OM&A) costs related to required and scheduled maintenance;

(d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

(e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and

(f) Dam Safety Condition Assessment and Maintenance requirements.

In Order 150/08, the Board varied this Directive and set a timeframe for Manitoba Hydro to file terms of reference by June 30, 2009. No terms of reference were ever filed, and in Board Order 73/13, the Board directed Manitoba Hydro to file an Asset Condition Assessment Study no later than the filing of the next depreciation study.

Manitoba Hydro submits that the Asset Condition Assessment Study filed during the current hearing meets the Board's directive, and that the utility also prepared an in-house distribution asset study, a transmission asset study by Kinectrics, and an in-house generation asset study. It further indicated that Manitoba Hydro's view on the life expectancy of its distribution assets was primarily based on age for planning and forecasting purposes, but Manitoba Hydro makes the decision to replace or refurbish assets based on the internal staff views of the condition of the specific assets. Manitoba Hydro also advised that in 2010 it purchased an asset investment planning system called Copperleaf to assist it in planning and prioritizing expenditures.

The Coalition was critical of the distribution asset study filed as part of Manitoba Hydro's GRA and stated that Manitoba Hydro provided a 'pitch', not a 'plan'. In the Coalition's view, the Board has been asking for a plan since 2008 and the quality of capital planning material filed is not appropriate for approving an increase in capital costs. According to the Coalition, both the Kinectrics report and the distribution asset study were available prior to CEF-13. Additional sustaining capital spending could have been included in CEF-13, yet Manitoba Hydro now insists that an additional $100 million annually is needed in CEF-14.

The Coalition suggested that the Board has not been provided with an adequate explanation of the capital spending optimization process, the types of alternatives considered, the reasons for significantly increasing distribution expenditures, and the anticipated performance outcomes. The Coalition provided information requirements mandated in other jurisdictions and suggested that such information might indicate different levels of required spending. The Coalition called the increases in distribution project spending individually desirable but collectively not sustainable. The Coalition also submitted that the spending increase with respect to buildings cannot be said to be linked to reliability and that the utility's asset planning report provides conclusions without sufficient supporting analysis. The Coalition requested that the Board find that it is unable to conclude whether the proposed magnitude of sustaining capital investment in 2014/15 and 2015/16 is prudent and direct Manitoba Hydro to provide a more robust asset health assessment and capital asset management strategy for the next General Rate Application (GRA).

The Coalition's submissions were largely mirrored by MIPUG, which suggested that Manitoba Hydro has not proved that it is adequately pacing and prioritizing its capital spending, and that existing asset conditions are good, with no urgent, short term replacement needs. MIPUG also argued that Manitoba Hydro's sustaining capital plan for generation assets is a placeholder, not an actual plan. In addition, since at the NFAT Manitoba Hydro alleged that it could safely maintain assets based on CEF-13 spending levels and the current spending levels fill some of the gap created by the discontinuance of Conawapa, the Board should view Manitoba Hydro's plan skeptically. MIPUG further

170A

As part of the quarterly reports, the Board should be provided with all capital cost justifications for Major New Generation and Transmission and other projects greater than $50 million approved by the appropriate Division Vice Presidents, even if such capital cost justifications are subsequently deferred by the Manitoba Hydro Electric Board or Manitoba Hydro's Executive Committee.

The Board accepts that Manitoba Hydro is faced with aging infrastructure and there may be a genuine need to expand sustaining capital expenditures. As such, for the 2014/15 and 2015/16 fiscal years, the Board accepts Manitoba Hydro's increased sustaining capital spending. However, the Board is not satisfied that Manitoba Hydro has adequately evaluated the long term pacing and prioritization requirements. The Board considers that top-down caps or placeholders are insufficient to justify increased spending in the future. As such, the Board's acceptance of the increased sustaining capital spending during this GRA should not be construed as an endorsement of Manitoba Hydro's long term sustaining capital plan.

To bridge what the Board considers to be an information gap, the Board expects Manitoba Hydro to file, by October 31, 2015, updated Terms of Reference and schedules for an Asset Condition Assessment. The schedules should contemplate completion of the Assessment in advance of the next GRA. In the Board's view, the Terms of Reference should, at minimum, include the items set out in Appendix G of this Order.

171

14

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

GENERAL RATE APPLICATION

2014/15 AND 2015/16

Before Board Panel:

Regis Gosselin	- Board Chairperson
Marilyn Kapitany	- Board Member
Richard Bel	- Board Member
Hugh Grant	- Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

June 17, 2015

Pages 4136 to 4427

174

be characterizing your face.

(BRIEF PAUSE)

MR. BYRON WILLIAMS: So back to slide 52 for a moment, Diana.

(BRIEF PAUSE)

MR. BYRON WILLIAMS: So when we saw this on behalf of our clients, Coalition-52, and remember, we made a lot of efforts to get it in the First Round and were unsuccessful, obviously, we're -- we're concerned when we see the heavy reliance upon age rather than robust parameters on the distribution side.

And we also ask, going to the second bullet, think back to what Mr. Thomson said. Modern capital asset planagement (sic) is about management at the portfolio level. We want to be able to compare a choice on the distribution business unit side with a choice on the generation side, with a choice on the transmission side. We want to put that together and -- and make a call. Talk about an apples-to-oranges analysis. We see on certain parts of the firm an

175

15

177

Public Utilities Board

Régie des services publics

Order No. 59/16

**ORDER IN RESPECT OF AN APPLICATION BY
MANITOBA HYDRO FOR
APRIL 1, 2016 INTERIM RATES**

April 28, 2016

BEFORE: Régis Gosselin, B ès Arts, MBA, CPA, CGA, Chair
Richard Bel, B.A.,M.A.,M.Sc., Member
Hugh Grant, Ph.D., Member
Marilyn Kapitany, B.Sc. (Hon), M.Sc., Member

Sustaining Capital Expenditures

Sustaining capital (also known as "base capital") spending is used to replace and refurbish existing assets, extend the electrical system to new customers, and to meet the load growth of existing customers. At the last General Rate Application, Manitoba Hydro proposed to increase its sustaining capital expenditures from $470 million to $570 million in 2014/15. Manitoba Hydro spent $559 million in 2014/15.

In CEF15, Manitoba Hydro plans to spend $577 million in 2015/16, which is the same level projected in CEF14. For 2016/17, CEF15 projects $610 million, which is $25 million more than projected in CEF14. Because sustaining capital expenditures are capitalized and not expensed, the increase of $25 million in 2016/17 has an immediate annual revenue requirement impact of only approximately $1 million and is not a significant driver of the 2016/17 proposed rate increase.

In Order 73/15 Directive 13, the Board directed Manitoba Hydro to file quarterly reports for all Major New Generation and Transmission projects. The reports were to outline the original budgets, budget changes, revisions to in-service costs, and how any material cost increases will affect revenue requirements and Manitoba Hydro's financial forecasts. Manitoba Hydro filed one report for the period July to September 2015, which details no substantive changes to the total project costs from what was presented at the last General Rate Application.

Manitoba Hydro's Asset Condition Assessment Process

Manitoba Hydro's proposed level of sustaining capital expenditures remains under scrutiny. In Directive 7 of Order 73/15, the Board directed Manitoba Hydro to file Terms of Reference for an asset condition assessment report for generation, transmission, and distribution assets. This Directive followed similar Directives in Orders 116/08 and 73/13.

Manitoba Hydro intends to engage a consultant to assist in refining and documenting Manitoba Hydro's asset management policy and strategy. Manitoba Hydro expects the consultant to recommend: "*key asset management processes and systems Manitoba Hydro should improve upon or develop, including a performance management framework, risk management assessments, operations and maintenance asset planning, adherence to industry accepted standards and ongoing audit reviews.*"

Following last General Rate Application, Manitoba Hydro engaged Kinectrics to audit the asset condition assessment methodologies for Manitoba Hydro's HVDC and distribution assets. Manitoba Hydro expects the results of this audit to be available at the next General Rate Application.

Manitoba Hydro reports that on a preliminary basis, Kinectrics found that its transmission asset assessment methodologies follow best practices. However, Kinectrics identified that Manitoba Hydro's distribution asset assessment methodologies and characterization should be enhanced. Manitoba Hydro has engaged Kinectrics to develop asset health indices and refine the distribution asset condition assessment methodologies and provided the terms of reference for this engagement.

Manitoba Hydro has also responded to the Board's direction to enhance its capital spending pacing and prioritization by engaging Copperleaf Technologies Inc. to assist in developing a corporate value framework methodology. The corporate value framework helps identify the set of investments that will deliver the greatest value to Manitoba Hydro. Concurrently, Manitoba Hydro is implementing software from Copperleaf that will help with investment planning and asset management.

In the Consumer Coalition's view, Manitoba Hydro has not provided an asset condition assessment and management plan which can support the sustaining capital expenditures which are portrayed in IFF15. The Consumer Coalition also submitted that Manitoba Hydro has still not addressed the information gap relating to sustaining capital expenditures.

The Manitoba Industrial Power Users Group (MIPUG) stressed the importance of completing the asset condition assessments and being able to test the pacing and prioritization of capital spending in a full rate review process. MIPUG's view is the current interim rate review process does not allow the parties or the Board to perform this review. MIPUG also stated that the forthcoming asset condition assessments will reduce financial risks by balancing ratepayer impacts with safety and reliability.

Board Findings

The Board reviewed Manitoba Hydro's quarterly report on Major New Generation and Transmission projects, filed in response to Order 73/15 Directive 13. The Board notes that this report omits budget information on the Bipole III transmission line, Dorsey converter station, and Manitoba-Minnesota Transmission Project construction contracts. Manitoba Hydro also did not file reports for April through June 2015. The Board sees value in assessing the progression of the budgets and potential changes on an ongoing basis over multiple reports, and so will reserve comment until additional reports are reviewed at the next General Rate Application.

The Board also requested, as part of the quarterly reports, that capital cost justifications for Major New Generation and Transmission and other projects greater than \$50 million be provided. While the capital project justifications for Bipole III and Keeyask have been previously filed and reviewed by the Board, the Board would like to clarify that if any capital project justifications are revised for existing projects, these should be filed with the quarterly reports.

In Order 73/15, the Board directed Manitoba Hydro to file Terms of Reference and schedules for an Asset Condition Assessment by October 31, 2015. This Directive also required the Terms of Reference to set out the items in Appendix G of Order 73/15. It is understood that Manitoba Hydro is carrying out the Asset Condition Assessments with support from sub-consultants. To date, Manitoba Hydro has only filed the Terms of Reference for the engagement of a sub-consultant to review the distribution asset

181

condition assessment methodology. An overall work plan or schedule has not been filed.

Manitoba Hydro has not filed Terms of Reference or schedules for internal reviews of the generation or transmission asset condition assessments. Both of these assessments are apparently underway as evidenced by Manitoba Hydro's filing of its response to Order 73/15 Directive 7. The Board is again requesting the Terms of Reference and schedules for these two assessments be filed with the Board by April 15, 2016.

Manitoba Hydro stated that providing asset condition information based on geographic categories for distribution assets would require considerable additional work and does not expect the additional information to provide incremental value. The Board will consider alternate categories that identify age and remaining life of various distribution assets to be acceptable and will vary its previous direction to Manitoba Hydro.

The Board will require Manitoba Hydro to file the complete asset condition assessment information for generation, transmission, and distribution at the next General Rate Application.

7.0 Power Resource Plan, Load Forecast and Demand-Side Management

Issues

Power Resource Plan

Manitoba Hydro annually prepares a Power Resource Plan, now known as Resource Planning Assumptions and Analysis, that identifies the domestic load and export commitments as well as the generation and import resources to meet the expected load.

The 2015/16 Resource Planning Assumptions and Analysis shows that Keeyask is expected to enter service in 2019/20 with full operation in 2020/21. Based on the most recent net load projections as set out below, on an energy basis, Keeyask is not needed to meet domestic load and existing export commitments on a continuous basis until 2030/31. However, the need for Keeyask to supply a potential export sales contract with SaskPower of 100 MW in 2024/25 is temporary. The following year, with the expiration of the Northern States Power contract, the entire output of Keeyask is surplus to Manitoba Hydro's firm commitments and domestic load until 2030/31.

According to the 2015/16 Resource Planning Assumptions and Analysis, new generation resources are not needed until 2033/34 due to a shortage of winter generation capacity. A shortfall in dependable energy does not occur until 2036/37. The earliest post-Keeyask date that new resources are needed is 2033/34 unless outages due to replacement or refurbishment of existing generating units advance this date.

Load Forecast

Manitoba Hydro annually prepares a Load Forecast of domestic electricity consumption, the most recent of which was prepared in 2015. The projected net Manitoba demand for electricity consists of the amounts projected in the load forecast minus any savings