EB-2013-0416

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2015.

SCHOOL ENERGY COALITION CROSS-EXAMINATION COMPENDIUM (Panel 2)

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Table 1
Summary of Distribution OM&A Budget
($ Millions)

Description	Historical Years						Bridge Year	Test Years				
	2010	**2010 Approved**	**2011**	**2011 Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sustaining	305.9	315.2	317.1	337.5	307.9	335.7	320.4	329.5	374.4	380.1	363.2	358.1
Development	12.3	11.7	15.8	12.0	14.7	11.1	18.4	15.4	17.7	17.0	17.4	17.8
Operations	18.5	20.2	18.1	20.9	21.0	22.0	30.4	30.2	34.4	34.8	42.2	41.0
Customer Services	114.7	117.2	113.3	113.4	116.7	148.6	133.7	117.9	116.3	114.7	113.5	115.4
Common Corporate Costs and Other OM&A	94.9	50.9*	85.5	46.5*	88.6	88.8	73.8	66.7	62.5	62.4	62.4	62.3
Property Taxes & Rights Payments	4.6	4.7	4.6	4.8	4.5	4.4	4.6	4.7	4.9	5.0	5.2	5.4
TOTAL	**550.9**	**520.0**	**554.4**	**535.0**	**553.4**	**610.6**	**581.3**	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

* The envelope reduction to OM&A from the OEB Decision was not spread across the work program areas but was included in other OM&A.

UNDERTAKING - TCJ1.14

Undertaking

Reference: Exhibit I, Tab 3.03, Schedule 9 SEC 30

To provide a copy of the balance scorecard for 2013 and 2014.

Response

Please refer to Attachment #1 for the balanced scorecard for 2013 and Attachment #2 for Q1 2014.

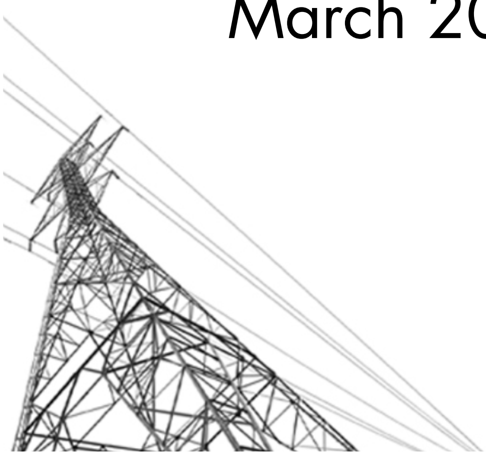
Hydro One Inc.
Corporate Scorecard
2013 Results

2013 Scorecard

Strategic Objective	Performance Measure	Year-End	
		Actual	Target
Productivity	Transmission Unit Costs (Capital and OM&A per Asset) %	7.8	9.8
	Distribution Unit Costs (Capital and OM&A costs per km of line) $'000/km	10.6	9.8
Reliability	Tx Duration of Customer Unplanned Interruptions on 115/230kV Network System per delivery point (minutes/delivery point)	12.9[2]	9.0
	Dx Duration of Customer Interruptions (hours per customer)	6.9	6.7
Satisfying Our Customers	Tx Customer Satisfaction (% satisfied)	81	82
	Dx Customer Satisfaction (% satisfied)	87	86
Employee Engagement	Employee Survey (Grand Mean)	3.93	4.06
Shareholder Value	Net Income After Tax ($M)	803	702
Injury-free Workplace	Medical Attentions (# of medical attentions per 200,000 hours worked)	2.5	1.9

Hydro One Inc.
Corporate Scorecard with 1st Quarter 2014 Results

March 2014

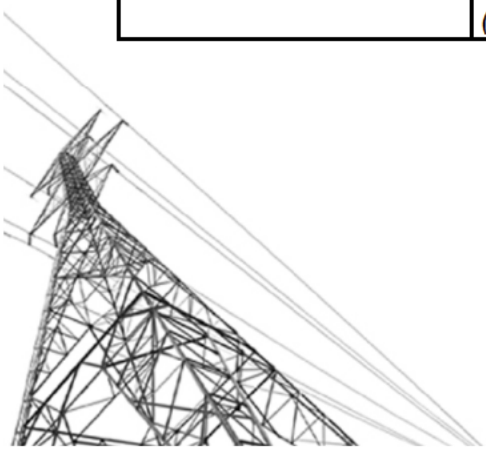


March 2014 Scorecard*

Strategic Objective	Performance Measure	Year-to-Date Actual	Year-End Target
Injury-free Workplace	Recordable Rate (OHSA Recordable) *(# of recordable per 200,000 hours worked)*	2.0	1.9
Satisfying Our Customers	Customer Satisfaction – Transmission *(% satisfied)*	--	84
	Customer Satisfaction - Distribution *(% satisfied)*	91	87
	Connection of New Services - Distribution *(% completed in ≤ 5 days)*	94	90
	Estimated Bills *(% of total bills issued)*	4.9	1.8
	No Bill Volume *(number of customers) ('000)*	47.1	8.0
	% Customers satisfied with escalated complaint resolution	--	N/A

March 2014 Scorecard*

Strategic Objective	Performance Measure	Year-to-Date	Year-End
		Actual	Target
Continuous Improvement & Cost Effectiveness in the Building and Maintaining Reliable Transmission and Distribution Systems	Transmission Unit Costs *(OM&A/Gross Fixed Assets) (%)*	0.8	2.9
	Distribution Unit Costs *(OM&A/Gross Fixed Assets) (%)*	1.6	5.7
	Customer Interruption Duration - Transmission *(minutes per delivery point)*	5.0	8.9
	Customer Interruption Duration - Distribution *(hours per customer)*	1.1	6.7
Maintaining a Commercial Culture that Increases Shareholder Value	Net Income After Tax *($M)*	240	
	Customer Service Recovery Cost *($M)*	12.9	48.0
	In-Service Capital – Transmission *(% of Plan)*	97	85
	In-Service Capital – Distribution *(% of Plan)*	87	87



July 30th Information Session: Question #8 - School Energy Coaliton (SEC)

Question

In the Hydro One Scorecard, the targeted amount for the in-service additions metric is 85% of budget. Provide dollar amounts and compare to Board approved amount and numbers consistent with this application.

Response

Part of the 2014 corporate scorecard target for Transmission is to achieve a minimum of 85% of the 2014 budgeted in-service capital addition (ISA) amount. For purposes of the corporate scorecard, the budgeted Transmission ISA amount is $920 million, and a minimum $782 million is required to meet the target (85% x $920 million = $782 million).

The 2014 OEB Approved ISA amount of $1,023 million was determined as part of EB-2012-0031 proceeding based on a plan developed throughout 2011. The budgeted 2014 ISA of $920 million was determined during the development of the 2014 business plan throughout 2013 and is more recent when compared to the 2014 OEB Approved amount.

This application includes an updated 2014 bridge-year ISA forecast of $863 million (Exhibit D1, Tab 1, Schedule 2, Table 1), which was developed in April 2014.

COST EFFICIENCIES/ PRODUCTIVITY

1.0 BACKGROUND

Hydro One Distribution identifies cost efficiency initiatives as part of its business planning processes, and also uses benchmarking to help identify areas requiring improvement. Provided below is an overview of Hydro One Distribution's efforts to improve cost efficiency in the past and initiatives being undertaken to continue improving cost efficiency in the future.

2.0 INTRODUCTION

Cost efficiency is a core element of the Hydro One Distribution strategy. Hydro One Distribution will continue to make prudent and responsible economic efficiency improvements consistent with its business strategy in order to deliver steady financial performance, sustain company assets and deliver safe, economic and reliable electrical energy. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One's vision is "to be an efficient and dynamic distribution and transmission company, leading innovation in delivering electricity in North America". The Company's strategic objectives to maintain this vision explicitly include a commitment to achieve productivity improvements and cost-effectiveness and develop related performance measures.

This emphasis on productivity is not new to the organization. Hydro One has a strong track record of realized cost savings related to our efficiency initiatives. In our previous Distribution and Transmission filings (EB-2007-0681 and EB-2008-0272), we gave evidence related to in excess of $380 million in cost savings from all aspects of the business including: labour utilization and productivity; new technology improvements; material and services costs; overhead costs; fleet costs; facility costs; business processes; and outsourcing of non-core business activities over the 2002 – 2006 period. Although Hydro One Distribution continues to look for opportunities to increase efficiency and reduce costs, the identification and implementation of additional cost efficiency initiatives in future years will be a greater challenge.

Hydro One's future challenges have increased when compared to those presented in our last Distribution and Transmission filings: the initiatives of the *Green Energy and Green Economy Act, 2009* ("GEGEA"), further significant growth in work programs, the attempt to address assets nearing their end-of-life, the replacement of end-of-life IT infrastructure and aging staff demographics coupled with a highly competitive labour market due to worldwide scarcity of core skills in the electricity industry. The staff demographics challenge is amplified by Hydro One's growing need for additional resources due to substantial work program growth as well as the increased demand for staff in the industry due to large infrastructure build programs initiated by various governments in the western world as part of their economic stimulus packages. Nevertheless, Hydro One continues to pursue opportunities to transform its business processes, which will ensure Hydro One maintains its vision of being an efficient and dynamic electricity distribution and transmission company.

3.0 PAST AND CURRENT COST EFFICIENCY INITIATIVES

A number of initiatives were identified and introduced between 2007 and 2008 to streamline the business, and many commenced prior to 2007, as identified in the Company's evidence filed in EB-2007-0681 and EB-2008-0272. Many of these continue to provide value to the organization, such as:

- Outsourcing initiatives;
- Lower wage rates for new employees as we attempt to address the existing aging workforce;
- Developing a more multi-skilled workforce;

- Increased staffing flexibility (e.g. use of hiring hall) to execute peak seasonal and project work;
- Improved and focused trades training programs;
- Business transformation initiative through the Cornerstone SAP project
- Implementation of new tools and technologies used for new connections;
- Implementation of new processes and tools in the field to enable improved planning, scheduling and reporting of work;
- Improvements in the fleet management business;
- The full use of temporary headquarters for work crews, reducing travel time and thereby increasing "wrench" time on the job;
- Targeted savings from strategic sourcing initiatives;
- The centralized operation of the distribution and transmission systems;
- Continued outsourcing of work activities;
- Integration and bundling of work, such as improvements to the management of equipment outages

Opportunities to increase efficiency and reduce compensation costs related to unionized staff are pursued through collective bargaining. These are discussed in Exhibit C1, Tab 3, Schedule 2.

Hydro One Distribution also uses benchmarking (internal and external) and information on best practices to find ways to operate the business more effectively and efficiently. Internal analyses are performed to compare performance across geographic regions and identify performance trends. The primary purpose of external studies is to compare relative performance and identify best practices others are using which may improve Hydro One Distribution's performance.

This benchmarking process provides Hydro One Distribution with knowledge about how its systems perform relative to the industry; assists with identifying its performance strengths and weaknesses as well as identifying effective practices utilized within the industry that may have application within Hydro One Distribution. Benchmarking studies provide Hydro One Distribution with performance information relative to the industry as shown in the Vegetation Management Benchmarking provided in Exhibit A, Tab 15, Schedule 2. Benchmarking and best practice results are provided to our planners and service provider staff to help them develop performance and productivity improvement initiatives.

Benchmarking studies in which Hydro One Distribution has participated include:

- First Quartile Consulting Benchmarking Community
- Canadian Electricity Association

Benchmarking has had positive results within Hydro One Distribution, including the following:

- Enhanced Distribution Network Reliability Reporting: Hydro One Distribution's equipment reliability data compared with data from other participating utilities across Canada, to identify the root causes of equipment-caused interruptions, so that patterns and predominant causes for interruptions can be identified and addressed.
- Use of a Balanced Scorecard Approach. Benchmarking has reinforced that the use of a Balanced Scorecard approach is a leading industry practice. Accordingly, Hydro One Distribution has developed Corporate and Operations Scorecards.

For key operating measures such as reliability and safety, comparator groups such as the CEA are available for Benchmarking comparisons. However for other indicators such as customer satisfaction, customized measuring tools are used and comparators are less reliable. In cost and financial comparisons accounting systems and work definitions, for example Hydro One has Distribution and Transmission; vary, so comparisons are less dependable. Also utilities are reluctant to publish cost data that may be used for other than best practices comparisons.

Table 1 identifies the estimated total incremental cost savings achieved from 2006 to 2008, and forecasted savings for 2009 to 2011 for Hydro One Distribution. While all savings estimates are for gross incremental cost savings, it should be noted that the implementation costs are taken into consideration as part of the business planning process discussed in Exhibit A, Tab 14, Schedule 1.

Table 1
Total Incremental Cost Savings – Distribution

	2006	2007	2008	2009 Bridge	2010 Test	2011 Test	Total
OM&A (non-Cornerstone) Savings ($M)	5.9	2.3	3.4	11.7	6.5	4.2	34.0
Capital (non-Cornerstone) Savings ($M)	4.6	0.5	1.1	4.5	4.0	2.2	16.9
Cornerstone OM&A Savings ($M)	0	0	0	4.2	1.1	3.3	8.6
Cornerstone Capital Savings ($M)	0	0	0	3.0	0.2	3.0	6.2
Total Savings ($M)	**10.5**	**2.8**	**4.5**	**23.4**	**11.8**	**12.7**	**65.7**
Total Spend** ($M)	**796.8**	**969.1**	**1,019.2**	**1,144.4**	**1,258.9**	**1,216.5**	**6,404.9**
Savings as % of Total Spend	1.3%	0.3%	0.4%	2.0%	0.9%	1.0%	1.0%

** Total Spend includes Distribution capital plus OM&A expenditures

Note that for purposes of the business planning model, the cost savings are identified as year over year "incremental savings" defined as savings over and above those already embedded in the costs of individual programs. Accordingly, the first year impact of a new initiative or enhancements to an initiative are identified and the target associated with that initiative is subsequently monitored to establish the actual savings achieved. Under this concept of incremental savings, the savings beyond the first year are considered to be "embedded" savings for purposes of the annual business plans and are therefore not included in the annual estimates of incremental savings unless enhancements to those initiatives are made. As a result, the incremental savings estimates substantially understate the savings from those initiatives that have a cost efficiency impact over more than one year.

Incremental savings in 2010 and 2011 are expected to increase from recent levels through such initiatives as:

- process improvements, including savings associated with implementation of the Cornerstone initiative;
- strategic sourcing savings;
- better planning and estimating, leading to reduced cancellations of outages; and
- job bundling to allow for improved efficiencies and overall reduced job costs.

As an indicator of productivity using costs per unit, *Distribution Unit Cost* is reported as Capital and O&M Costs per km and included in the Corporate Scorecard. We realize the productivity numbers will be going up due to increased infrastructure and program costs, however we will continue to benchmark to identify whether these increases are comparable with peer utilities and whether we are Q1/Q2 when benchmarked against comparable Utilities. The 2009 proposed target for the unit cost indicator was established based on the approved 2009 Business Plan, including any cost savings.

For the Distribution Unit Costs, the most effective measure is benchmarking performance against comparable utilities. In this way we can demonstrate how productive we are against peer utilities.

We also look to internal comparisons of performance through measures such as: Distribution Lines Capital and O&M Spending per route KM; Customer Hours per route KM (Exclude Major Events); and Customer Interruptions per route KM (Exclude Major Events).

However while recognizing the accomplishments listed above, the need for continuous improvement in performance management is noted. Therefore we will:

- Increase our focus on internal productivity comparisons.
- Continue developing key performance indicators
- And ensure our cost allocation accounting processes can reflect improvements in cost efficiency comparisons

4.0 BUSINESS TRANSFORMATION

In addition to continuing to utilize benchmarking and best practice information, Hydro One Distribution is taking advantage of a unique set of circumstances to transform its business over the next few years, and to help the Company pursue productivity improvement.

The unique set of circumstances noted above includes:

- **Significant growth in work programs** resulting from the GEGEA, requiring increased staffing resources and support systems. This work program growth is driven by increased demand in specific geographic areas, the need to replace aging assets, system expansion and generation mix. This expanded work program provides the opportunity to achieve greater economies of scale, leverage standardized processes and design standards and implement new work methods.
- **Replacement of the core enterprise wide IT systems**, which have reached end-of-life. Many of these systems are being replaced within an integrated corporate business transformation project, already in progress, named Cornerstone. This project will facilitate changes in business processes to allow for more effective use of information resulting in improved work execution.
- **Substantial shift in staff demographics** which will result in a large proportion of current staff retiring over the next decade, and backfilling with new staff on a relative scale not seen in decades. As the result of a renewed collective agreement, new Society-represented staff are already being brought in at lower salary ranges (the salary range for all bands will be equivalent to 70-100% of current bands, replacing the existing 80-115% ranges). As well, different skill mixes are being sought while at the same time allowing for skills and knowledge transfer from senior staff; different work methods are being implemented; new staff are being trained on the new replacement core business process

and IT systems (as noted in the previous bullet) and will not need retraining as required by existing staff, etc.

This set of changes in the operational environment provides Hydro One Distribution with an opportunity to transform its business in a step level change over the next few years which will result in a variety of efficiency and effectiveness improvements over this period.

4.1 Economies of Scale

The increase in the work program has also been enabled by Hydro One Distribution's work-based approach to staffing as discussed in Exhibit C1, Tab 3, Schedule 1. Specifically, to address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by not hiring all regular (permanent) staff. Rather, knowledgeable, experienced and highly skilled internal staff plan and direct the "peak" work of non-regular (temporary, hiring hall and contract) staff, which provides the needed flexibility to manage in a cost effective manner. This flexibility provides a variable workforce which is matched to the peaking requirements of the workload at minimum costs. Specifically, the workload volume ramps up in the second quarter of the year and peaks in the third quarter; the flexible external workforce of non-regular staff is engaged in numbers to match this varying volume of work. To the degree possible, within the constraints of our labour agreements, contractors are also engaged to undertake "turn-key" projects.

Other work program improvements that leverage economies of scale include: outsourcing and strategic alliances with suppliers and contractors to enable faster turnaround times for material and services.

Hydro One is also implementing an IT Architecture Strategy to provide additional opportunities to glean further economy of scale savings as work programs expand.

4.2 Cornerstone Value Realization

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One Distribution's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. Value added, beyond the value from a like-for-like replacement, is expected in all four phases of Cornerstone. Some of the value levers are: improved efficiency in work processes, enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution, and improved internal and supplier contract compliance through the reduction in non-purchase order spending for direct purchases of materials and services. For further information on Cornerstone, please see Exhibit D1, Tab 3, Schedule 7.

4.3 Corporate Culture

An ongoing focus for Hydro One's Distribution business has been the implementation and nurturing of a continuous improvement culture that recognizes the need to look for positive change in everything we do. Hydro One Distribution will take advantage of the opportunity presented by the anticipated substantial staff attrition due to demographics and coincident creation of new positions due to work program growth, to build on the existing corporate culture to further enhance its core characteristic of continuous improvement.

It is recognized that a key differentiator in terms of business success is employee engagement. By engagement, we mean the extent to which employees commit to someone or something in their organization, how hard they work, and how long they stay as a result of that commitment. The link between engagement and productivity is well supported through research, and it is very clear: engaged employees provide greater discretionary effort and greater discretionary effort leads to increased productivity.

Consequently, Hydro One Distribution embarked on a program committed to maintaining high levels of employee engagement. Managers at the local level throughout Hydro One are developing impact plans with their staff that will create specific and measurable plans to increase employee engagement.

5.0 SCORECARDS AND PERFORMANCE MANAGEMENT

While cost and productivity indicators can provide insight into the efficiency of operations, to be effective requires a broader base of measurement. To accomplish this Hydro One has and is developing Scorecards that provide an overall perspective of performance management.

Included in these are internal reporting vehicles such as the Corporate Scorecard that measures and reports on organizational level issues using a Balanced Scorecard methodology. This Scorecard is supported and supplemented by Operational and Line of Business Scorecards that both aggregate to the Corporate and also provide specific data for decision making.

Supplementing these internal performance reporting tools are compliance or requirement reporting to regulatory and industry organizations. These include the Ontario Energy Board's Customer Service Quality Requirements (ESQRs) which will now be reported annually.

A new Canadian Electrical Association membership requirement is the monitoring and reporting of sustainable development. There is a commitment to CEA stakeholders to continue to improve overall sustainable development performance and report progress in a transparent and timely manner.

School Energy Coalition (SEC) INTERROGATORY #30

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference:
Please provide a copy of the Oliver Wyman productivity study undertaken by the Applicant in 2011. Please explain how that study was utilized.

Response

The Oliver Wyman Study can be found in Attachment 1 of this interrogatory. It was previously filed as Exhibit A, Tab 17, Schedule 2, Attachment 1 of proceeding EB-2012-0031.

At the conclusion of the Hydro One Transmission filing (EB-2010-0002) the Board noted that Hydro One must be in a position to provide more robust evidence that compensation increases are matched with demonstrated productivity gains. Hydro One selected Oliver Wyman to study current market standards for measuring productivity and to suggest potential internal metrics for measuring productivity at Hydro One.

Oliver Wyman conducted a broad market survey of U.S. and Canadian utilities. The final report showed:

- most utilities looked at productivity metrics as part of a balanced scorecard to support the understanding of trends of service quality and total cost metrics;
- none of the participants tracked productivity across all business functions, relying instead on a sampling of different sections of work;
- no regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction, but instead focused on outcome metrics of overall service quality and total costs; and
- there was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently.

Hydro One used this information to develop its own productivity metrics in the context of a balanced scorecard to measure productivity, reliability, customer satisfaction, safety and shareholder value.

December 15, 2011

Measuring Productivity at Hydro One

OLIVER WYMAN

Contents

1

Executive Summary

Oliver Wyman was engaged to report current market standards for measuring productivity and suggest potential metrics for measuring productivity at Hydro One.

As part of this effort, Oliver Wyman conducted a broad market survey of US and Canadian utilities and contacted many regulators directly to assess how productivity measures were used. Across Canada and the US, Oliver Wyman contacted 30 utilities and 17 commissions via over 350 documented emails, phone calls and requests for information.

No regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction. Instead commissions focused on 'outcome' metrics of overall service quality metrics (SQM) and total costs. In many cases, the commissions directed Oliver Wyman to contact utilities directly as the management of productivity was considered the utilities responsibility.

Most utilities did look at productivity metrics internally as part of a balanced scorecard to support the understanding of trends of the service quality and total cost metrics. The productivity metrics found suggest that none of the participants track productivity across all business functions, relying instead on a sampling of different sections of work.

Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

After analyzing Hydro One's major costs and interviewing many of their staff, 25 metrics have been suggested as candidates to measure productivity, which account for 22% of total O&M and Capex labor related costs. However, as with any measurement, the development of these metrics should be evaluated in the light of the cost to measure them, any potential negative effects they may create (e.g., adverse incentives for employees), and the ability to roll up these up to corporate scorecard measures.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

2

Background

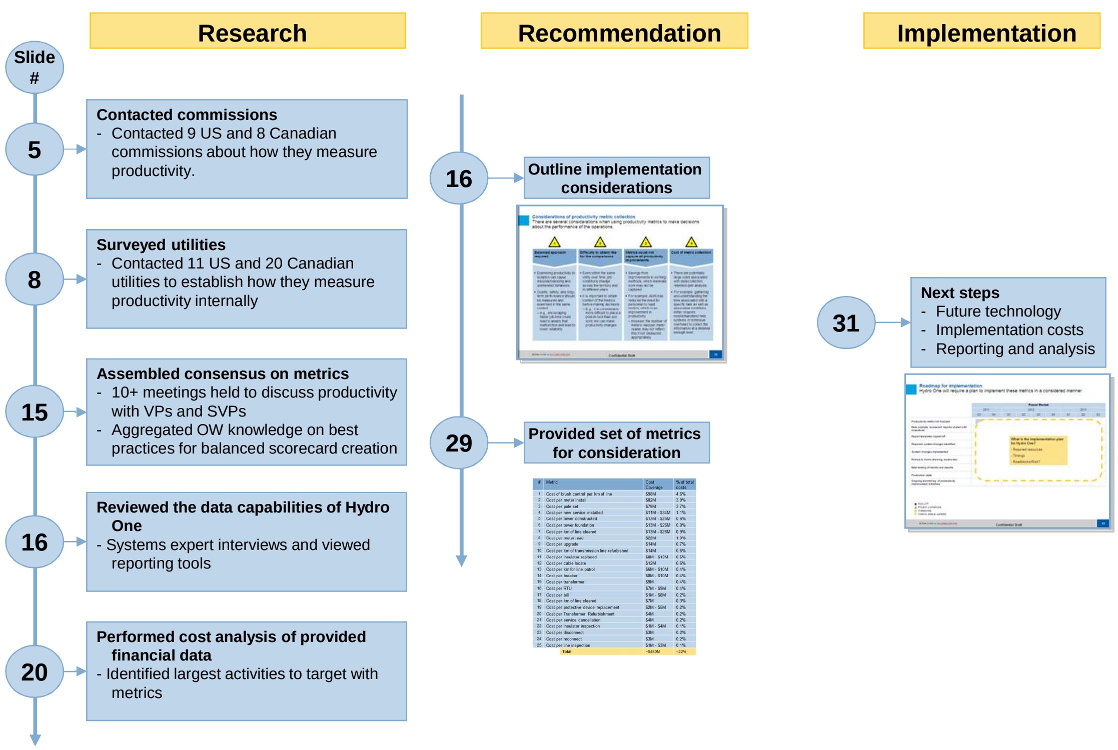
> "In its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and other expectations for further information on compensation and efficiency comparisons.
>
> The Board directed "Hydro One to revisit its compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America."
>
> Toward that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses".
>
> The Board went on to describe its expectation that Hydro One "be in a position to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate case. The Board will expect compensation increase to be matched with demonstrated productivity gains".
>
> **Extract from Hydro One RFP # SCO-1000152789, March 2nd 2011**

To satisfy all aspects of the Ontario Energy Boards requests, Oliver Wyman was engaged alongside Mercer. Mercer was responsible for updating the compensation benchmarking study with 2011 data and separately reported changes in relative compensation levels. Oliver Wyman was to provide perspectives on industry best practices for productivity measurement.

3

Report Roadmap

The figure below represents the shape of the report, consisting of three sections; research, recommendations and implementation. The research section contains the findings from utilities and commission research and an analysis of Hydro One's cost. Using the findings from research, a list of the challenges of metric collection was created to coincide with the recommended set of metrics. To implement the data collection and reporting process steps were recommended to ensure that the recommended metrics would provide useful and accurate information.



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Findings from Regulatory Commissions

17 Regulators across the US and Canada were requested to provide which methodologies they had for measuring performance. Nine commissions were in the US and eight commissions were in Canada.

In addition to direct contact via a combination of calls, e-mails and requests for information, a review was performed of publicly filed documents such as rate cases, studies and other regulatory dockets.

The findings were fairly consistent across the different regulators. 15 regulators collected 134 different service quality metrics between them during regular filing processes. 12 of the commissions had annual filing requirements for service quality; these were Alberta, Ontario, Quebec, Massachusetts, New York, Pennsylvania, Michigan, Ohio, Illinois, Connecticut, New Jersey and California.

United States commissions

Canadian commissions

Service quality metrics were the most standardized of metrics across the regulators. Reliability metrics such as system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI), and system average interruption duration index (SAIDI) are being collected by the majority of regulators on a regular basis. Customer call center metrics such as % of calls abandoned, and % of calls answered in under 30 seconds were also collected by many regulators.

It was standard practice to collect cost metrics with seven commissions collecting 67 cost metrics. All regulators require financial information to be filed during a rate case, generally as part of the utilities cost of service which include various financial statements.

No commission was found to regularly collect any productivity metrics. Both the Manitoba Public Utilities Board (MPUB) and Nova Scotia Utilities and Review Board (NSUARB) had collected productivity metrics, but not on a regular basis. The MPUB collected "average time per call" and the NSUARB commissioned an ad hoc study containing "calls handled per agent per day."

The summary results from each commission are found in the tables in the appendix. For a detailed review of each commission's metric collection practices please see the appendix.

Rank	Metric Type	Common Metrics	# Found
1	SQM	System Average Interruption Frequency Index	14
2	SQM	Customer Average Interruption Duration Index	13
3	SQM	System Average Interruption Duration Index	11
4	SQM	% of Calls Abandoned	7
5	SQM	% of Calls answered in under 30 seconds	5
6	SQM	Average speed of answer	5
7	SQM	% of In-service appointments met	5
8	SQM	Momentary Average Interruption Frequency Index	3

Further studies identified

There were several other studies identified in the course of research that have related topics and provide additional summary information about the state of metric collection.

CAMPUT

The Canadian Association of Members of Public Utility Tribunals (CAMPUT) commissioned a study in 2009 to review the use of benchmarking as a regulatory tool for public utilities in Canada.

The study reviewed current practices of regulators to determine the information which regulators currently collect from utilities, finding that only service quality and cost data was being collected. The extent to which service quality and cost were being collected varied across each commission.

The study looked at the perspectives on benchmarking from the sides of both the regulators and the utilities. It was determined that utilities focused on performance assessment, target setting, performance improvement and reliability support. Whereas regulators would like to use benchmarking for ratemaking, compliance, audit monitoring and reducing information risk.

Various factors inhibiting the use of benchmarking were found, including the difference in demographics and geography in which utilities operate. The methods of data collection between utilities could pose problem unless strict definitions and processes are created for each metric under consideration. CAMPUT suggested using normalizers, a comparable peer panel and good metric choice in order to mitigate each of these hazards.

The list of metrics which CAMPUT recommended for benchmarking were: call center performance, billing accuracy, customer complaints, system average interruption frequency index, system average interruption duration index, customer average interruption duration index, asset replacement rates for distribution, transmission and substation assets, customer care, bad debt, O&M costs, corporate services costs, safety indices, line losses indices, and conservation indices

CAMPUT suggested starting with stakeholder discussions to determine the metric definition and data collection processes. The next step was identified to start a pilot project to test the feasibility of benchmarking these metrics. The pilot project would start in jurisdictions where the data is already being collected. The pilot project would test the current processes, identifying solutions to the problems as they become apparent.

Hydro One is currently participating in the first pilot of this initiative and is providing mostly reliability (CAIDI, SAIFI, etc.) and some call center information (ASA, Service Level)

Ad hoc studies

Multiple studies were found which were commissioned by regulators during a rate case. These studies either reviewed or benchmarked different aspects of the utility.

The Nova Scotia Utilities and Review Board (NSUARB) commissioned Accenture Inc. to perform a review of Nova Scotia Power’s (NSPI) corporate services due to its recent restructuring. Accenture Inc. benchmarked the corporate services function across a similar peer panel and found that NSPI was an “average to good” performer.

The NSUARB commissioned an operational review of NSPI, which was done by Kaiser Associates. As part of Kaiser Associate’s review, a benchmarking study was administered on operating, maintenance and general expenses (OM&G). The study showed that NSPI operates at a lower normalized OM&G cost than its competitors. The Kaiser study benchmarked one productivity metric; calls handled per agent per day.

5

Findings from Utility Survey

Oliver Wyman conducted a survey to determine how different utilities measure their performance internally through cost, service quality and productivity metrics to establish best practices in the industry.

Respondents

13 utilities across North America were included in the survey panel; the utilities included those in transmission, distribution and generation.

The survey consisted of two parts: the first part was to collect the performance metrics (cost, productivity and service quality), the second part was to determine the automation level of the data collection, the percentage of total cost covered by the performance metrics and what function was responsible for the data collection. For the purposes of this report and the survey, productivity was considered to be an activity-level metric such as "cost per pole" while service quality and cost were higher level metrics.

There was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently. The reason for the disparity may have been because each utility was choosing metrics to track the success of different corporate goals.

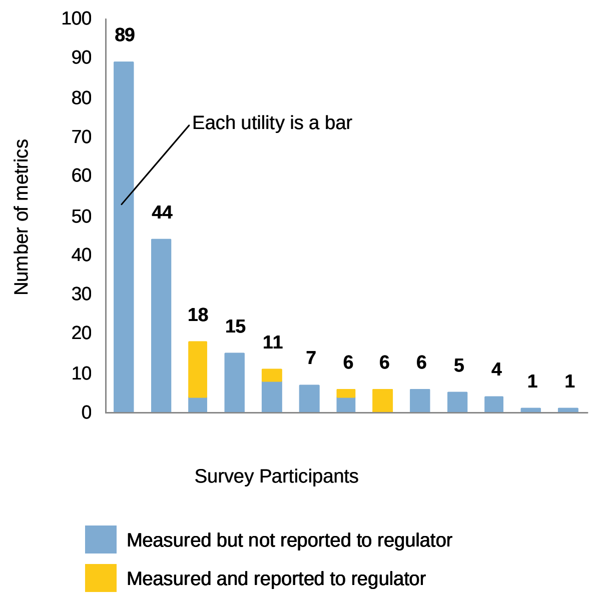
Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

Cost

The cost metrics collected by utilities detail overall spend in business categories, with metrics such as "distribution spend per customer."

Of all the cost metrics reported internally, 12% are reported to regulators, and 22% are part of a benchmarking effort but not necessarily reported to regulators.

Cost metrics collected in survey



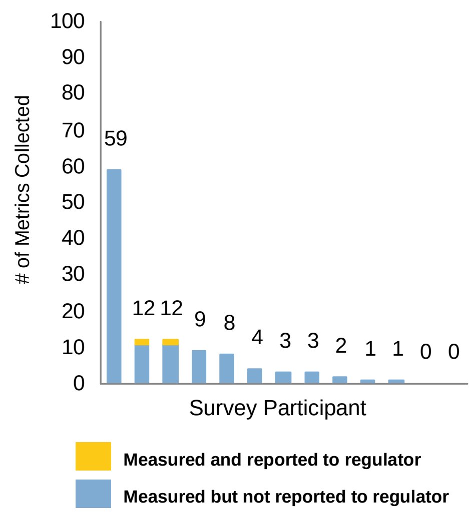
Productivity

12 of 13 utilities collected at least one productivity metric. Productivity is measured at an activity-level; with a median of six metrics per utility, it is likely that most utilities are not measuring productivity across a large portion of their activities and total costs.

The productivity metrics collected are generally not benchmarked, and none are regularly reported as to regulators.

Four strategies were identified for measuring productivity: cost per unit (e.g. cost per pole), units per FTE (e.g. bills processed per FTE), reducing nonproductive time (e.g. average travel time), and time taken per activity (e.g. average time per call).

Productivity metrics collected in survey



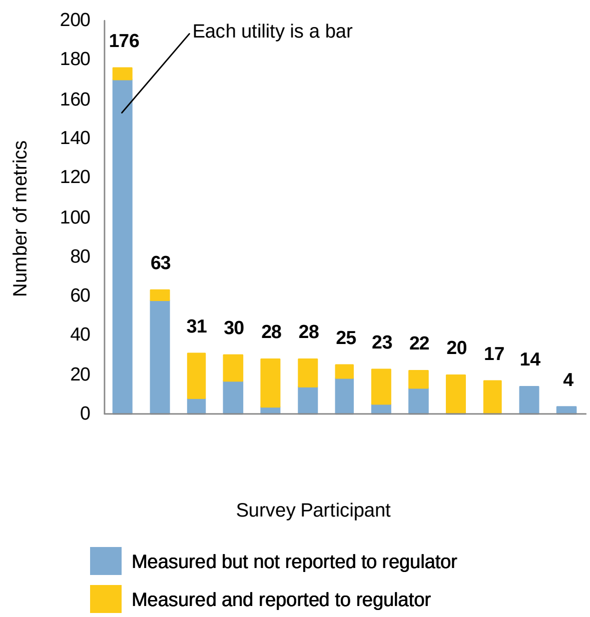
9

Service Quality

The utilities surveyed place a strong emphasis on measuring service quality as these are often the primary concern of regulators, shown by the number of metrics that were reported to regulators.

The metrics collected can be grouped into five categories: system reliability (e.g. system average interruption duration index), safety, customer call center performance (e.g. % of calls answered within 30s), customer facing operations (e.g. % meters read), customer satisfaction.

Service quality metrics collected in survey



System reliability metrics were standard across utilities with a majority of the utilities collecting; system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI).

Common Metrics

It was difficult find metrics that were universal across utilities as each utility measured differently. The metrics below are those that were tracked by at least 2 utilities in the survey.

Cost

- Net income
- Net income from operations
- Operations Maintenance & Administration (OM&A) costs per customer

Productivity

- Turnover
- Cost per call
- Meter reads per FTE
- Lost time accident rate
- First call resolution rate
- Average time per call

Service Quality

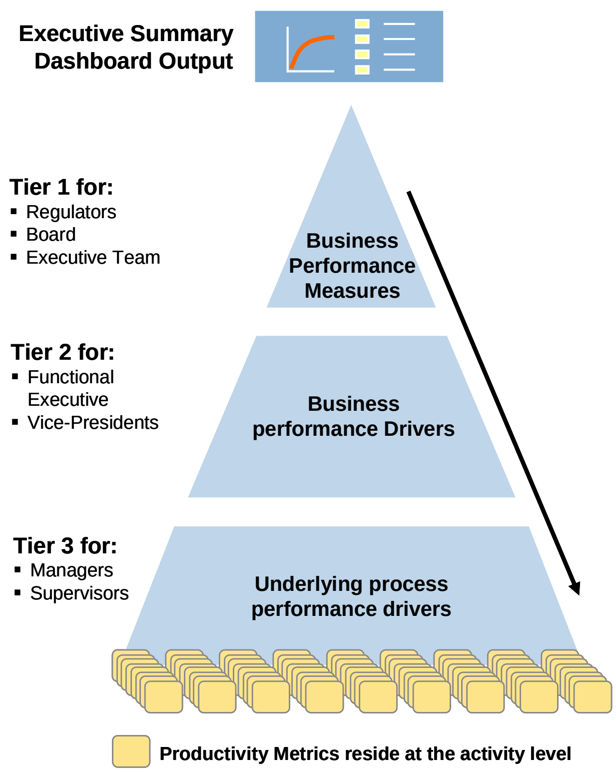
- System avg. interruption frequency index (SAIFI)
- Customer avg. interruption disruption index (CAIDI)
- % of Calls answered in 30s or less
- System avg. interruption duration index (SAIDI)
- % of Calls abandoned
- % of Meters read
- % In-service appointments met
- Customers experiencing multiple interruptions (CEMI)
- Bill accuracy rate
- Average speed of answer
- Occupational Safety and Health Administration Incidence Rate
- Momentary avg. interruption frequency index (MAIFI)
- Emergency response time
- SAIFI – Distribution Only
- # of Off-cycle meter reads/month
- SAIDI – Distribution Only
- Occupational Safety and Health Administration Severity Rate
- # of Post-final adjustment mechanism processed per month
- New service installation factor
- # of Sites billed/month
- # of Sites not billed/month
- Regulatory commission cases per 1000 customers
- Damages per 1000 elect. Locate requests
- Customer satisfaction – overall
- Customer experience long interruption duration (CELID)
- CAIDI – Distribution Only
- CAIDI – Storm
- Average number of energizations per month
- Average number of de-energizations/month
- Average System Availability Index (ASAI)
- % of Meters not read within 6 months
- % of Completed off-cycle meter reads >5 days
- % of Calls answered in under 20 seconds
- Vehicle accident frequency rate

6

Perspectives on Productivity Measurement

Performance measures should "cascade" in various tiers, with productivity metrics normally measuring activity-level performance in the bottom tier. There are three main tiers when measuring performance; business performance measures, business performance drivers, and underlying process performance drivers.

Business performance measures are used for strategic decision making and to align an organization to the company's strategy and vision (e.g. reliability, customer satisfaction, and overall cost to serve). These measures are often reviewed by regulators, the board of directors and the executive team, typically as part of a balanced scorecard.



Business performance drivers are measures that directly impact business performance measures. These metrics can be used to identify opportunities for different business units or operational groups as well for ongoing management education (e.g. customer service cost per customer, inventory turns, or # of outages longer than 4 hours). Business performance drivers are utilized by functional executives and vice-presidents.

Underlying process performance drivers are measures that impact business performance drivers. These drivers enable the identification of specific process improvements and provide ongoing employee education (e.g. cost per call, cost per meter read, or cost per locate). The diversity of work in a utility at this tier would require thousands of metrics to capture productivity covering the entire workforce; therefore it is important to select a representative portfolio of metrics which account for the diversity of work.

Most utilities select the portfolio of metrics using criteria that best fits their business needs. A metric may need to be used in conjunction with other metrics to meet the criteria stated below.

	Metric Criteria	Description	Details for Hydro One
1	**Targets principal labor cost areas**	Build an understanding of labor costs and target the biggest activities first. Choose enough metrics to measure a large proportion of total costs	Major activity costs should be assessed by productivity metrics. Hydro One has several repetitive large costing activities such as locates, pole replacement, tree trimming, etc.
2	**Covers a wide cross section of work**	Choose metrics which measure the major functions of the business.	Categorizing costs into T&D and O&M v Capex allows selection of a stratified sample of the major cost areas. This ensures a balanced wide range of productivity metrics from different areas of the business.
3	**Based on Data Capabilities**	Only use metrics from data that have high confidence levels.	For example do not measure pole replacement costs by location ground type, if ground type is not consistently recorded at Hydro One.
4	**Allows consistent measurement over time**	Metrics should be precisely defined, so year on year comparisons are meaningful	With the introduction of SAP and increases in the resolution of base data, it is important that changes in metric calculations are understood.
5	**Appropriate measurement costs**	Metrics should balance usefulness and costs to measure.	At Hydro One, in order to perform the exact tracking of various field resources, mobile handheld tracking systems, would have to be implemented which are very expensive as it is a new set of hardware, new tracking system and field process restructuring and training
6	**Applicable over long time frame**	Corporate metrics should not be specific to a particular project, but rather valid for multiple years	Project specific metrics are not suitable for long term productivity tracking. This should not prevent larger projects (e.g. Bruce to Milton) to have additional tracking and metrics or be tracked via Earned Value methodologies.
7	**Focus on key areas of customer interest**	Metrics should primarily focus on areas of high concern and/or are important to its customers.	Hydro One has many customer facing activities, which have a large effect on their customer satisfaction. For example average days to complete a locate or percentage of calls answered within 30 seconds

Considerations of productivity metric collection

There are several considerations when using metrics to make decisions about the performance of operations which are; using a balanced approach, the difficulty of obtaining like for like comparison, metrics not capturing all productivity improvements and the cost of metric collection. These considerations detail the various risks associated with data collection, measurement, and use.

Using a balanced approach

A balanced approach to metric reporting considers all factors of safety, quality and long-term concerns when choosing which metrics to include. A balanced approach is required because efforts to increase productivity could lead to a reduction in safety or quality standards as people try to game the system. This is especially a danger if promotions or bonuses are related to metric performance.

Example: A supervisor knows that their bonus will be determined by the metric ‘Cost per km of line cleared’. To increase their bonus, they schedule cheaper vegetation clearance jobs with sparse vegetation that were not critical for another year and push back some difficult line clearance with more impact. The metric improves in the short term, but costs rise later in the year when the uncut vegetation causes an outage in the more critical area.

This problem can be mitigated by building a clear division of labor between work planners and executioners, and not providing an incentive for the planners to affect the metric in either direction. It is necessary to be careful when setting up management and compensation structures to avoid any conflict of interest. In-depth safety training will educate workers about the risks of forgoing service quality and safety standards to expedite the completion of a job. Tracking safety standards within the portfolio of metrics will ensure that the level of safety and service quality does not erode as efforts to increase productivity continue. Measuring a balanced set of metrics prevents undue focus on any one metric.

Like for like comparison

Not all work units are of similar difficulty level, so productivity improvements could be hidden by changes in average job difficulty. Even seemingly homogenous work activities will have their own unique challenges. Each job has its own required travel time, soil type, ease of access, conditions etc. which change the overall cost of the job, these changes have the capacity to dilute increases in productivity.

Example: One year the percentage of pole replacement jobs done in rock increases from 15% to 20%. Since replacing a pole in rock rather than soil is much harder to perform, the cost per pole replacement increases. This effect masks any productivity gains.

Activities should be defined so the differences inherent in each job are not significant. In the pole example replacing a pole in rock, versus earth, could be tracked as two separate activities. This could be done through additional data collection or by defining the metric by zones. Otherwise it is possible to use comparisons across longer time frames to allow for averages to become a better indicator of true performance. This also eliminates any seasonal effects.

Breaking apart activities into similar groups in this manner allows for better like for like comparisons. However, sometimes obtaining the base data to accomplish this is prohibitively expensive, therefore, longer comparison periods should be used instead to normalize the effects of the differences.

Capturing all productivity increases

System productivity enhancements might not be captured by direct consideration of metrics. Initiatives to improve productivity often eliminate manual work streams, in favor of cheaper automated systems. These process changes can cause ‘per work unit’ metrics to deteriorate, while still being an overall productivity improvement. When considering how successful Hydro One has been at increasing productivity all of these savings should be included.

Example: Increased automated monitoring of system availability gives responders the ability to respond faster to outages. However, automated monitoring routinely detects smaller outages, negatively affecting system reliability metrics such as SAIFI.

Savings from new technology programs should be tracked through dedicated programs. It is necessary to compare the total system setup and maintenance costs with the realized savings in order to track how the system influenced productivity. During the transition period to automated meter reading, the cost of meter reads can be divided by the total number of automated reads plus number of manual reads. Similarly for the SAIFI example, during a transition period the metric can be calculated via the old and new methods. When a new baseline for the automated monitoring system is established, the older calculation method can be stopped.

Cost of metric collection

Measuring any metric requires an investment in all of the following areas: setup, data collection, data storage, and reporting and analysis. The benefits of the increased knowledge and understanding from reporting and analysis must outweigh the costs of measurement.

Example 1: Mobile time trackers can be given to all field engineers, recording exact locations and the type of work being performed at any given time. They are expensive to roll out, but allow for much more detailed time studies.

Example 2: Pole replacement costs increase by 30% in a reporting period. After two days of investigation it is found that this is because zone 6 incorrectly reported the number of poles replaced. Two days of overhead costs incurred for no gain in understanding.

In example 1, a detailed cost benefit analysis would be required - a large upfront cost would provide an ongoing wealth of interesting information. In example 2, there is a more straightforward answer; the system should be redesigned to highlight missing input data to prevent losing two days for a simple tear down analysis. Normally reports are setup once and can then be run on an automated schedule, with little to no manual effort. The total costs of measurement and reporting should be understood upfront and compared to benefits in order to decide on its implementation.

Overview of productivity metrics at utilities

Many utilities do measure productivity metrics, as they consider the benefits of understanding their business outweigh the costs and challenges of measurements. The considerations of productivity measurement show that measuring genuine productivity changes is a difficult and sometimes inexact science. There is no automated or fool proof mechanism for capturing all the contextual knowledge required to understand trends and changes in a metric over time. Similarly there is no ‘silver bullet’ metric that does not have any challenges or limitations.

Despite these caveats, productivity metrics are an integral part of the management of a utility. Tracking productivity assists utilities in understanding and explaining the drivers behind changing costs, for use internally and in explanation to regulators. Productivity metrics can assist in targeting corporate initiatives at poorly performing areas and to assess the success of corporate initiatives and of managers.

Most utilities use a balanced set of metrics to obtain the clearest picture of performance. The set of metrics ensure no significant costs of the business are untracked and that productivity is not degrading safety or service quality. Utilities have analysis teams which place results into the context of business cycles and external influences (e.g. weather). The trends in headline metrics are explained by the underlying supporting metrics which is illustrated in the cascade of performance metrics.

Utilities leverage advanced IT systems such as mobile tracking devices to produce detailed productivity metrics without creating large indirect costs. Field workers activities are tracked at a granular level, allowing for a clearer view on productivity without requiring labor intensive and inaccurate detailed timesheets. Activity-level information can be captured on the job site, which helps to further segment activities for like to like comparisons. Utilities that do not have a mobile data collection system to capture every minute of a crew’s day, relying on manual entry of time at the end of a day may sometimes result in incorrect data input or inadequate time breakdown which can generate misleading metrics.

7

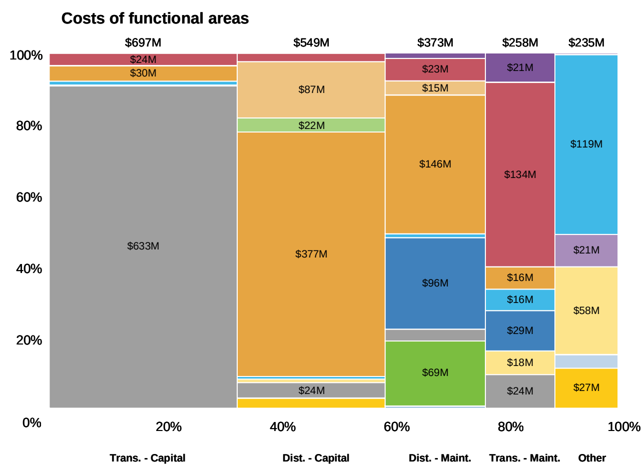
Targeted Cost Analysis

Overview of methodology

Oliver Wyman evaluated Hydro One's project-level data in a four step analysis to better understand how a suite of productivity metrics could be developed.

Step 1: Build overall cost map by functional areas

Projects were grouped into functional areas to ensure that metrics capture major sections of the business.

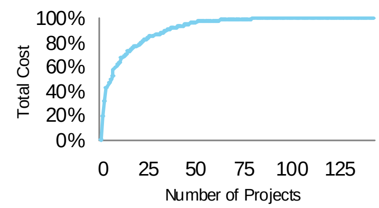


Step 2: Filter cost groups

The four major functional areas were targeted; transmission capital, transmission OM&A, distribution capital, and distribution OM&A. The 'Other' category was not targeted because it includes projects which do not relate to labor productivity. Some of the projects include real estate maintenance as well as IT projects such as SAP. Targeting the major areas allows for a sufficient proportion of the total cost to be tracked. In each of the four functional areas the irrelevant and uncontrollable costs were removed. These are costs that would fluctuate and obscure the productivity gains that are being tracked. In this initial analysis, material costs were removed, which are mainly driven by base commodity prices. Further filters could also target contracts and interest, as these costs do not directly correlate to labor productivity. Interest expense is based on market rates and does not change based on productivity. A productivity metric which includes the cost of contracts might look better if a contract is negotiated with a lower price, or it may be more expensive if internal skilled labor is more efficient. While 'cost productivity' may change, these scenarios may not necessarily represent a 'workforce productivity' change.

Step 3: Concentration of cost in major projects

It is necessary to understand how dispersed or concentrated projects are within each functional area in order to effectively track performance. Multiple large projects were selected in order to get a large proportion of the costs associated with each functional area. Within these projects understanding which activities meet the metric criteria and represent the largest proportion of cost is mandatory as these are the activities which will be tracked with metrics.



Step 4: Identify suitable metrics for activities

Using the criteria for metric selection, specific metrics within each project and their cost coverage were identified. Some projects were not covered by metrics because the activities which represent the project are not objectively measurable; they either have a short time frame or non-repetitive activities. Short term projects do not allow for long term comparison of the metrics covering these activities, without the comparison tracking the metric becomes a nonproductive effort. Projects may be composed of non-repetitive activities; these activities cannot be measured using productivity metrics as there would be no comparisons available, and tracking it would provide no relevant information.

During the stakeholder session held on October 19, 2011, a point was raised that even if activities are not consistent from activity to activity, a larger group of them should have the same profile if examined over a long period of time. The example discussed was 'Trouble Response'. While it was agreed that no Trouble Event could be compared to the next because they are very different in nature, over a long period of time a metric looking at the large group of them should be possible. With respect to Trouble Events, it was discussed that even over an annual cycle, the 'portfolio' of events would vary because weather patterns change from year to year affecting the frequency and character of trouble events. So, a longer period of time (e.g., 3 years) would have to be examined.

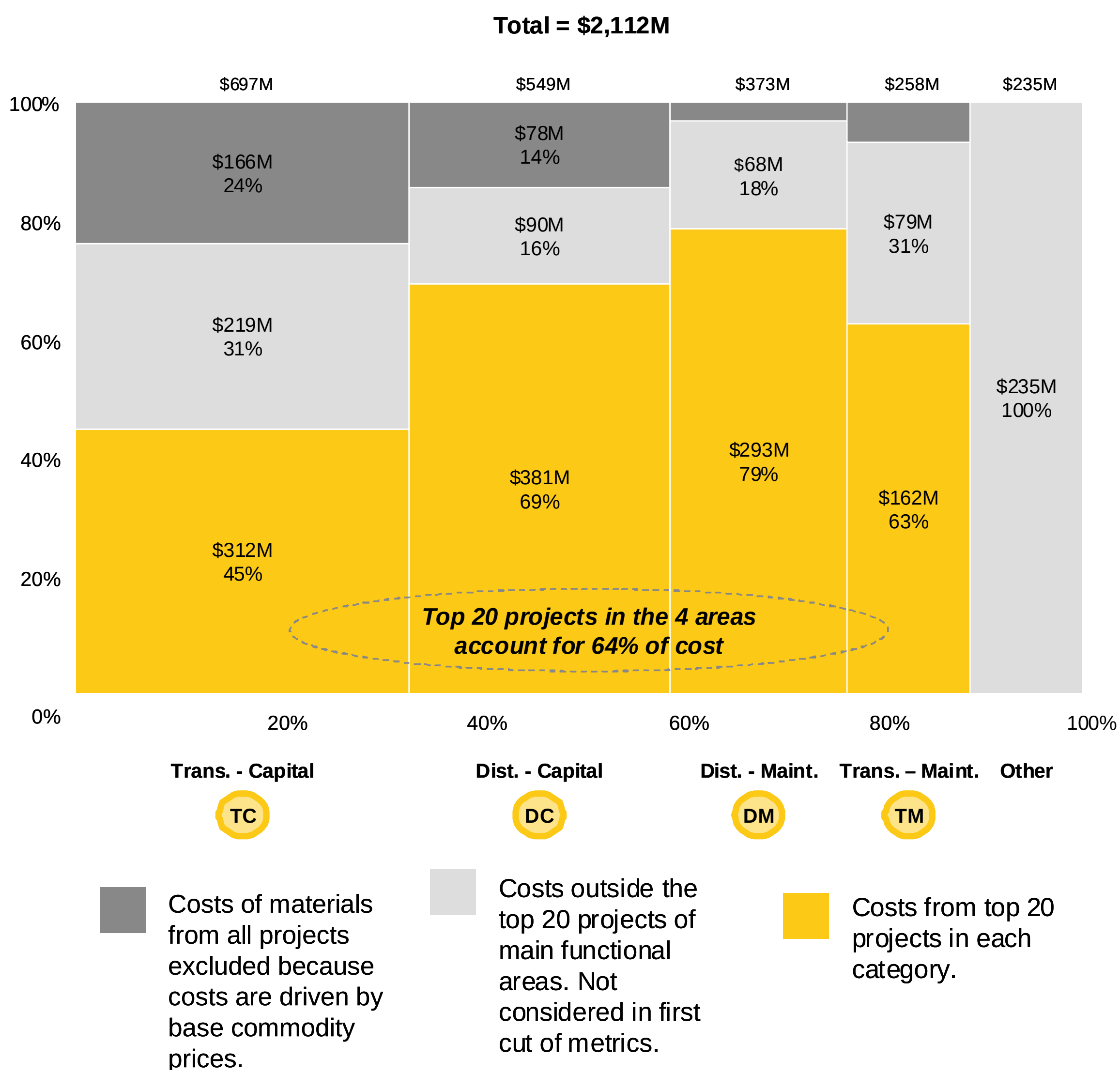
In this report we identify those activities that have potential to be measured over a long period of time. However, we believe that the long duration over which they must be examined prevents them from being used as a management tool to drive improvements in productivity. Management cannot use them on a regular basis to identify and drive improvements. Therefore, while we identify them in their respective sections, we do not recommend pursuing them at this time to drive productivity improvements.

Principal cost driver analysis

Productivity metrics should span all business areas in order to best represent the productivity for Hydro One as a whole. Understanding the cost drivers for each of the main projects in the functional areas will allow for tracking productivity across a large proportion of total cost.

Cost map of the 80 projects in focus from the four functional areas

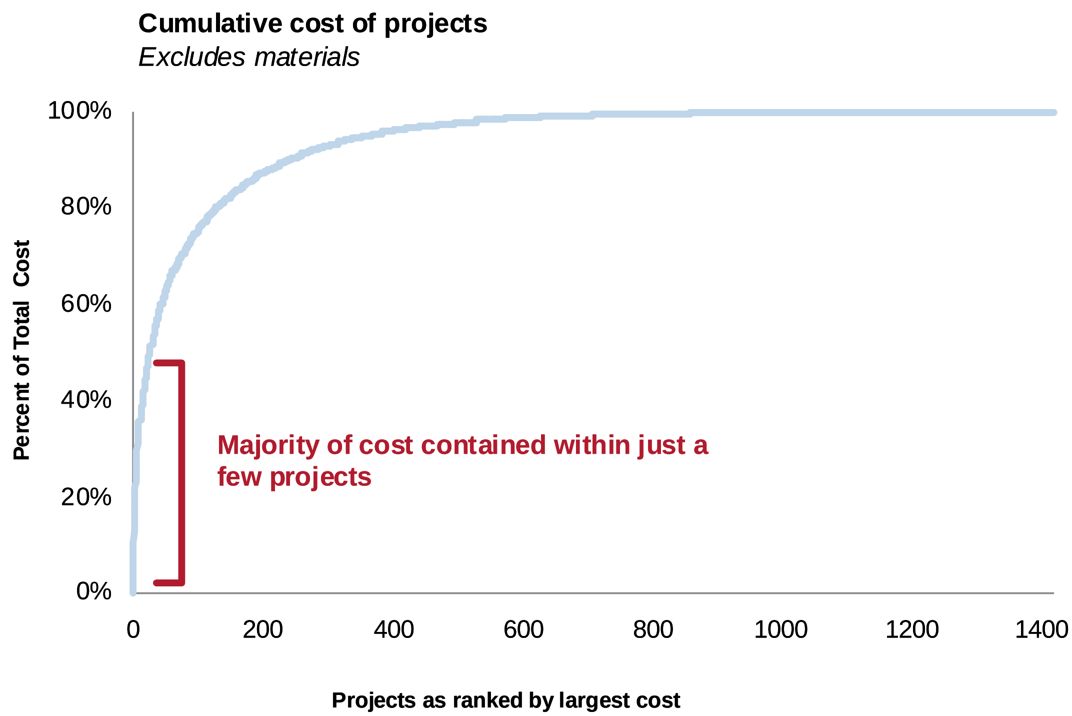
To arrive at a list of activities (projects) that may be measured for productivity, the largest activities (measured by cost) were examined. Material costs are excluded from the analysis as they do not represent workforce productivity and can fluctuate with many uncontrollable factors. Targeting the major cost areas (projects) allows for a large proportion of total cost to be covered, by a smaller number of metrics the top 80 projects (20 from each major cost area, T OM&A, T Capital, D OM&A, D Capital) cover 64% of the total cost.



Note: All costs are approximate and have been annualized from May 2011.

Trends in project costs

Another representation of the concentration of costs is to examine what each incremental activity (project grouping) adds to the total cost of the total. Each major cost area reveals that a large proportion of total cost is covered in a small number of projects. A few metrics targeting these projects cover a large percentage of cost and work. The cumulative cost of activities shows that 80% of costs are from the 126 largest projects, 75% from 96 projects, 50% from 29 projects, and 24% from 6 projects.



**Note: Costs are approximate values and have been annualized from May 2011. Costs do not include projects with negative or zero costs.*

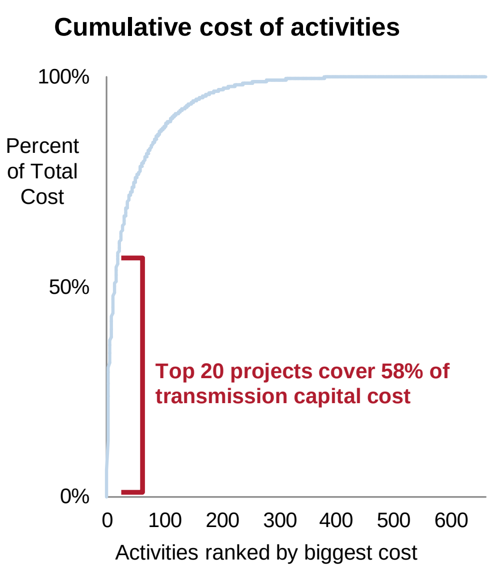
For each major cost area on the following pages we outline the concentration of costs into the largest activities (projects) and illustrate what metrics could be used to measure each.

As stated in the methodology section metrics are identified that have the most promise for measuring productivity based on the criteria outlined. In addition we identify additional metrics that could be compared over longer time frames (e.g., annual or greater), however we do not recommend pursuing these for purposes of improving productivity because they do not provide the regular view into performance required for managers to make useful changes.

Transmission capital project metrics

The top 20 largest Transmission Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 58% of the total relevant transmission capital spend. However, because these projects are generally one-time in nature and do not endure over time, only nine of the twenty largest transmission capital projects have suitable metrics.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time. For example the "Burlington Switchyard Reconstruction" has many activities that are likely unique because of the project nature of the work.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	**Bruce to Milton double circuit line**	▪ Cost per km of line cleared ▪ Cost per foundation ▪ Cost per tower constructed (*metrics do not cover all costs)	$129M	24%
2	**PC&T systems**	▪ Inconsistent over time	$17M	27%
3	**Wood pole replacement program**	▪ Cost per pole	$14M	29%
4	**Burlington switchyard reconstruction**	▪ Project based	$13M	32%
5	**WATR**	▪ Inconsistent over time	$11M	34%
6	**Kirkland Lake Reconnect Idle Line**	▪ Project based	$11M	36%
7	**Wood pole replacement program**	▪ Cost per pole	$11M	38%
8	**Mitigate reliability problems of Shunt capacity**	▪ Inconsistent over time	$11M	40%
9	**Build New Duart TS**	▪ Project based	$10M	42%
10	**SF6 Breaker Replacement Program**	▪ Cost per breaker	$10M	44%
11	**Detweiler: Add 230 kV, 350 MVAr SVC**	▪ Project based	$9.1M	45%
12	**Replace 2010 Richview Transformers**	▪ Cost per transformer	$9.0M	47%
13	**RTU Replacement Program**	▪ Cost per RTU	$8.7M	49%
14	**Nanticoke: 500 kV, 350 MVAr SVC**	▪ Project based	$8.0M	50%
15	**Kirkland Lake TS - Install SVC**	▪ Project based	$7.4M	51%
16	**Protection Replacement Program**	▪ Cost per protective device replacement	$7.3M	53%
17	**BSPS Mods for Bruce for 2009**	▪ Project based	$7.1M	54%
18	**Line Refurbishment Program ('10-'12)**	▪ Cost per km of transmission line refurbished	$6.9M	55%
19	**Line Refurbishment Program ('09-'10)**	▪ Cost per km of transmission line refurbished	$6.8M	57%
20	**Demand Capital - Equipment Failure**	▪ Inconsistent over time	$5.3M	58%
		Legend **Totals**	**$312M**	**58%**

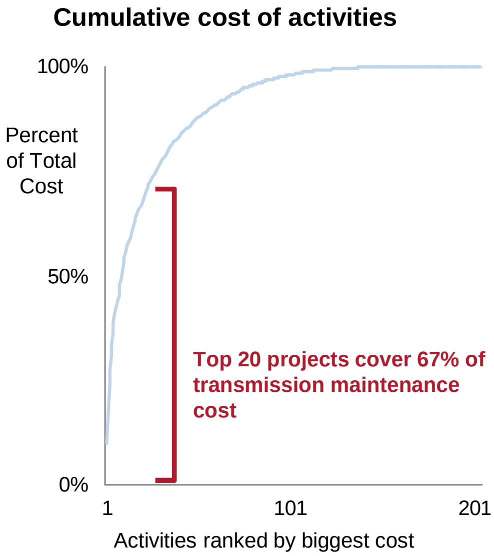
Relevant Metric	Potential metric examined over long time periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

Transmission OM&A project metrics

The top 20 largest Transmission OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 67% of the total relevant transmission OM&A spend. However, because these activities (projects) do not contain discrete work activities that are consistent over time, only 8 of the areas have suitable metrics. For example, "Corrective Maintenance" contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Preventive Maintenance - Planned (PMO)	▪Cost per km for line patrol ▪Cost per insulator inspection	$24M	10%
2	Transmission Site Maintenance	▪Inconsistent over time	$18M	17%
3	Tx Lines - RoW Brush Control	▪Cost of brush control per km of line	$16M	24%
4	Corrective Maintenance - Demand	▪Inconsistent over time	$16M	31%
5	Corrective Maintenance - Planned	▪Inconsistent over time	$13M	36%
6	Operating Facilities Support & Mtce - OGCC IT	▪Inconsistent over time	$12M	41%
7	Tx Lines - RoW Line Clearing	▪Cost per km of line cleared	$7.2M	44%
8	P&C NOEA / PQ / Spares / Database / Info. Mgnt	▪Inadequate time frame	$6.3M	47%
9	PSTS Leased Circuits	▪Inadequate time frame	$5.9M	49%
10	2011 Tx ECS Stds Development	▪Inadequate time frame	$5.3M	51%
11	Field Switching - Stations	▪Inconsistent over time	$5.2M	53%
12	P&C Preventative Maintenance / Inspections	▪Cost per inspection	$4.8M	55%
13	Overhead Tx Lines - Preventative Maint. - PL	▪Inconsistent over time	$4.7M	57%
14	P&C EMERG Corrective Maint. and Trouble Call	▪Cost per call out	$3.9M	59%
15	Environmental Mgt- Demand Corrective Mtc	▪Inconsistent over time	$3.7M	60%
16	Transformer Midlife Refurbishment Program	▪Cost per Transformer Refurbishment	$3.7M	62%
17	Overhead Tx Lines - Condition Assessment - PL	▪Cost per km for line patrol	$3.2M	63%
18	Overhead Tx Lines - Demand Work - PL	▪Cost per KM of line	$3.1M	65%
19	Transformer Oil Leak Reduction Program	▪Inconsistent over time	$3.1M	66%
20	2011 Cyber Sustainment	▪Inconsistent over time	$2.8M	67%
		Totals	$162M	67%

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

Distribution capital project metrics

The top 20 largest Distribution Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 80% of the total relevant Distribution capital spend. Only 5 of the areas have suitable metrics, however because many of the activities are not repeated consistently over time. For example, "Storm Damage" contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.

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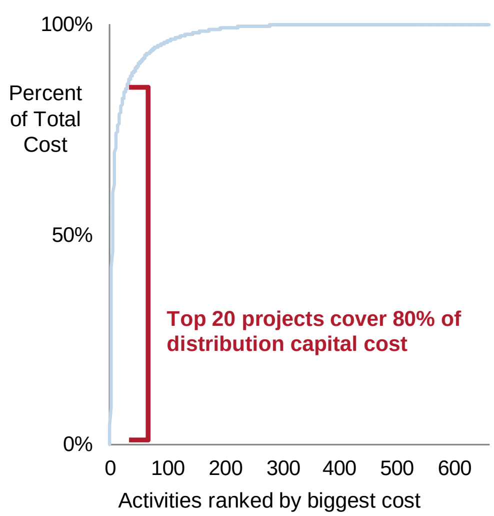
Cumulative cost of activities



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Smart Metering - Capital	▪Cost per meter install	$82M	17%
2	End of Life Replacement of Wood Poles	▪Cost per pole	$53M	28%
3	Residential, Subdivision, Expansion	▪Cost per new service	$45M	38%
4	Dx Capital Storm Damage	▪Inconsistent over time	$38M	46%
5	Joint Use and Relocations (Yearly)	▪Cost per relocation	$37M	54%
6	ADS Project - Phase 1 - Dx Capital	▪Project based	$21M	58%
7	Dx Capital Trouble Call Poles & Equipment	▪Inconsistent over time, materials	$17M	62%
8	Cornerstone Phase 4 - CIS - Capital	▪Project based	$17M	65%
9	Customer Upgrade	▪Cost per upgrade	$14M	68%
10	Other, EI, Data Collection	▪Inconsistent over time	$11M	71%
11	2010 Connection of Micro-Generation Facilities Und	▪Cost per connection	$9.3M	73%
12	Upgrade - Other	▪Inconsistent over time	$4.8M	74%
13	Dx Capital Trouble Call Damage Claims	▪Inconsistent over time	$4.5M	75%
14	2009 Joint Use and Relocations	▪Inconsistent over time	$4.4M	76%
15	Large Project	▪Project based	$4.3M	77%
16	2011+ Distribution System Modifications	▪Project based	$4.2M	77%
17	Dx Capital Post Trouble Call & Power Quality	▪Inconsistent over time	$3.7M	78%
18	Service Cancellations	▪Cost per service cancellation	$3.6M	79%
19	Facilities Improvements DX (segment alignment)	▪Inconsistent over time	$3.5M	80%
20	Dx Capital Trouble Sub and UG Cable	▪Cost per event	$3.4M	80%
		Totals	**$381M**	**80%**

Legend

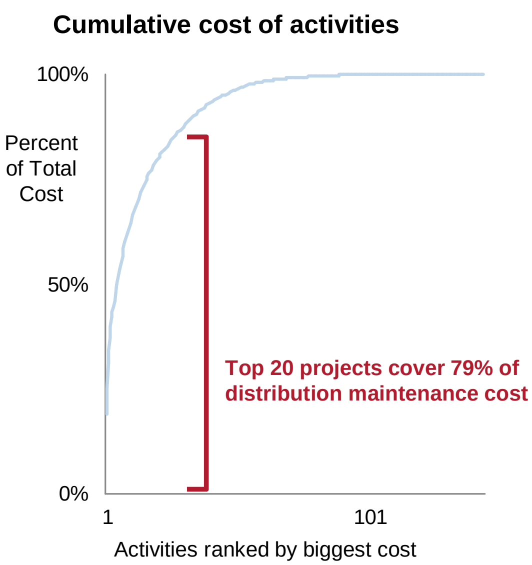
Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Distribution OM&A project metrics

The top 20 largest Distribution OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 79% of the total relevant Distribution OM&A spend. 8 of the areas have suitable metrics because many of the activities are not repeated consistently over time. For example, “Trouble calls” contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Dx RofW Vegetation Management - Line Clearing	▪Cost of brush control per km of line	$70M	19%
2	Dx O&M Trouble Call	▪Cost per trouble event	$46M	31%
3	CSO Sustainment	▪Outsourced	$40M	42%
4	OH Defect Correction & Insulator Replacement	▪Cost per insulator replaced	$14M	46%
5	Smart Metering - OM&A	▪Cost per meter read	$14M	50%
6	Dx Overtime and Forestry Storm Costs	▪Cost per storm (OT and forestry)	$14M	53%
7	Dx RofW Vegetation Management - Brush Control	▪Cost of brush control per km of line	$12M	57%
8	Dx Cable Locates	▪Cost per cable locate	$12M	60%
9	Dx Vegetation Management - Job Plan & Notify	▪Inconsistent over time	$8.3M	62%
10	CSO Service Support - 3rd Party - MR & Billing	▪Cost per bill	$8.0M	**64%**
11	Meter Reading - Prov. Lines	▪Cost per meter read	$7.8M	67%
12	CSO Regulatory Compliance - MR & Billing	▪Inconsistent over time	$7.4M	69%
13	Dx Disconnects / Reconnects	▪Cost per disconnect ▪Cost per reconnect	$6.5M	70%
14	CSO Service Enhancements - MR & Billing	▪Inconsistent over time	$5.8M	72%
15	Small External Demand (Yearly)	▪Inadequate frame	$5.6M	73%
16	OPA Programs	▪Inconsistent over time	$5.5M	75%
17	DS Stations O&M	▪Inconsistent over time	$5.2M	76%
18	PCB and Other Waste Management	▪Inconsistent over time	$3.9M	77%
19	Field Special Investigations	▪Cost per field investigation	$3.7M	78%
20	CSO Regulatory Compliance - Collections	▪Inconsistent over time	$3.5M	79%
		Totals	**$293M**	**79%**

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Summary of recommended metrics

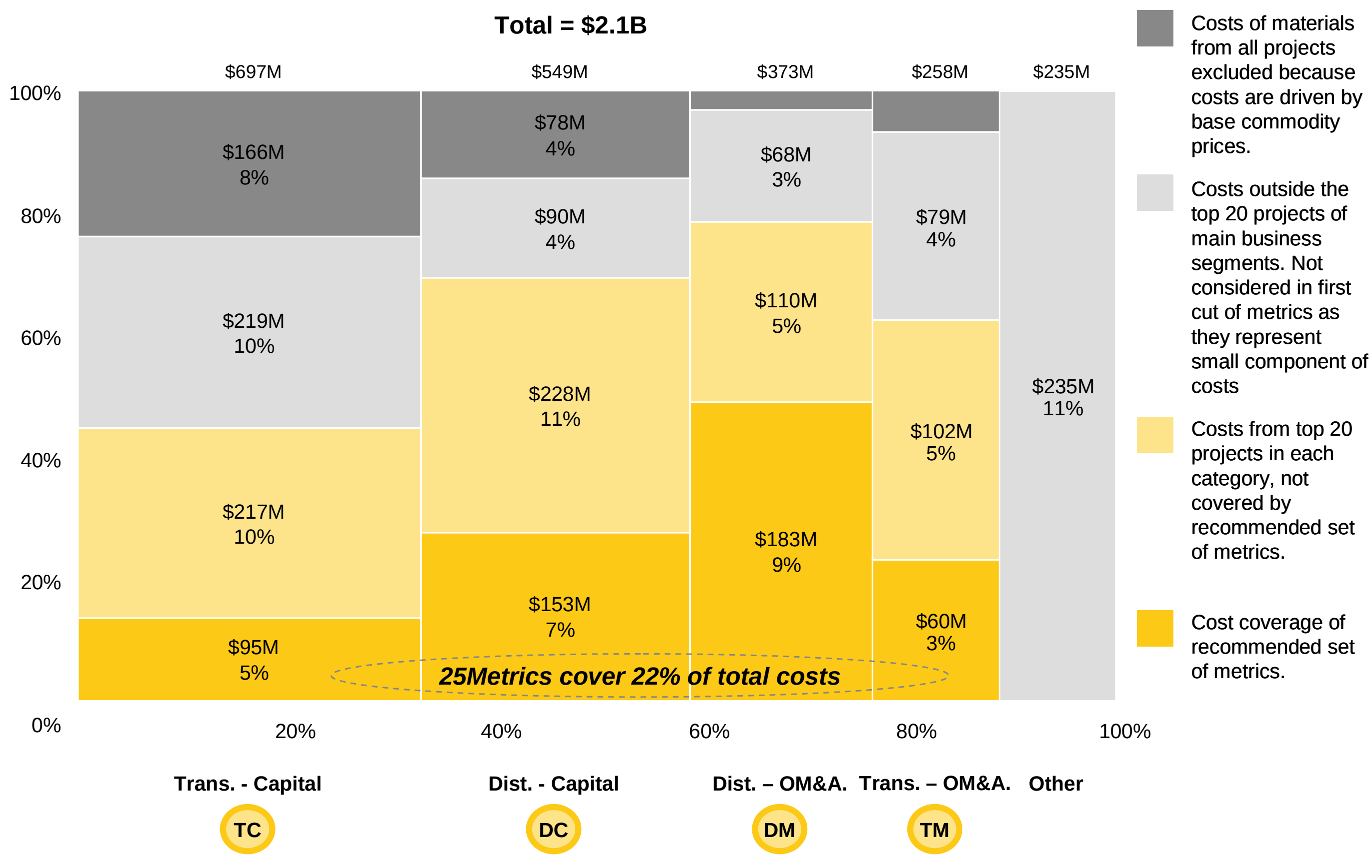
Aggregating the metric choices from the four main functional areas represents a good coverage of total cost; twenty five selected metrics account for approximately twenty two percent of total cost. Some metrics cover multiple activities across different functional areas (e.g. cost per pole). Further subdivision of these metrics may be required to allow better comparisons (e.g. cost per pole could be sub divided into cost per pole per ground type). Estimations of cost coverage were based on project titles, further validation with the business would be required to confirm the assumptions made. A large number of projects could not be understood from titles well enough to suggest metrics.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

Cost coverage of selected metrics

The aggregated metrics are shown in the overall cost map below. Distribution OM&A has the largest coverage due to having more repetitive activities, suitable for metric collection. Transmission capital has mostly "one-off" project work and a higher percentage of unique, non-repetitive projects.



Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

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Next Steps

Roadmap for implementation

Hydro One will require a plan to implement and of these recommended metrics, and their associated costs, within a timeline. The plan will need to consider what resources will be required for implementation as well as what risks they foresee during implementation.

	Fiscal Period								
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Productivity metric list finalized									
Beta example 'scorecard' reports shared with executives									
Report templates signed off									
Required system changes identified									
System changes implemented									
Rollout to Users (training, access etc)									
Beta testing of results and reports									
Production state									
Ongoing monitoring of productivity improvement initiatives									

What is the implementation plan for Hydro One?

- Required resources
- Timings
- Roadblocks/Risk?

Potential challenges for utilities in measuring productivity

Initial data collection efforts and interviews highlighted a number of areas of potential challenges for utilities in reporting productivity metrics. These challenges include: data validation, activity segmentation, partial completions, granularity, mobile data collection, indirect costs and their ability to roll up to corporate scorecard measures.

Data validation

In order to ensure useful productivity measurement, the data must be inputted into an enterprise system accurately and consistently. The total number of unit activities needs to be correct to get a valid "cost per unit" measurement. The users of the enterprise system will need to be trained to ensure that the data collected is reliable. Monitoring and auditing compliance should be added to the management review process to ensure the data in the system can be used with a high degree of confidence.

Activity segmentation

Certain activities have widely disparate costs depending on location, ground type, weather etc. and require further segmentation to provide useful measurement (e.g. type of ground for pole replacements). It will be necessary to determine how to segment these activities to ensure that like for like comparisons can be made.

Partial completions

The system should capture 'partial completions' for larger activities or activities with multiple steps. Collecting these partial completions will ensure that a metric does not look poor until the activity is fully completed but rather show a steady result through the duration of the activity.

Granularity

The system data warehouse should capture costs at a granular level. Otherwise there are concerns regarding whether the granular buckets are being used appropriately and if the data is accurate at that level. Effective measurement at an activity level requires high confidence in the data at the most granular levels. The highest level of data confidence is generally achieved through utilities using mobile/handheld equipment.

Mobile data collection

Mobile data collection allows for full tracking of field workers activities and the time taken to complete those activities. The completeness of data that arises from the use of mobile tracking devices allows for highly accurate analysis and better activity segmentation. Using timesheets to track activity level data, which are filled out at the end of the day by the field workers is a labour intensive process. This manual data collection can lead to misleading results as the field worker may be required to estimate the time he spent on each activity throughout the day.

Indirect costs

Are indirect costs traced carefully using an activity based costing model or similar? It is necessary to ensure that certain activities are weighted with appropriate indirect costs. A regular review of how the indirect costs are weighted among each activity will ensure that it is accurate each year.

Generally, each of these challenges can be addressed; they just require additional expense and/or additional time. It is necessary and appropriate for utilities to make deliberate decisions about how to spend their time and money to generate the productivity metrics that add value to the organization. There are costs of implementation to consider, as well as the costs of ongoing maintenance of any system/process put in place to generate the appropriate measurements.

Performance management design criteria

Performance management needs to focus on the following four key building blocks; measures, measurement, goals/targets and action plans and the iterative process.

Measures

The measurement process should not be an overwhelming task; a select portfolio of metrics meeting the criteria and measuring a large portion of business activities and costs should be used. The measures should include the three tiers of performance measurement to allow for strong analysis for those utilizing the metrics at each level. A mix of leading vs. lagging measures will allow for accurate forecasting as well as strong cause and effect analysis.

Measurement

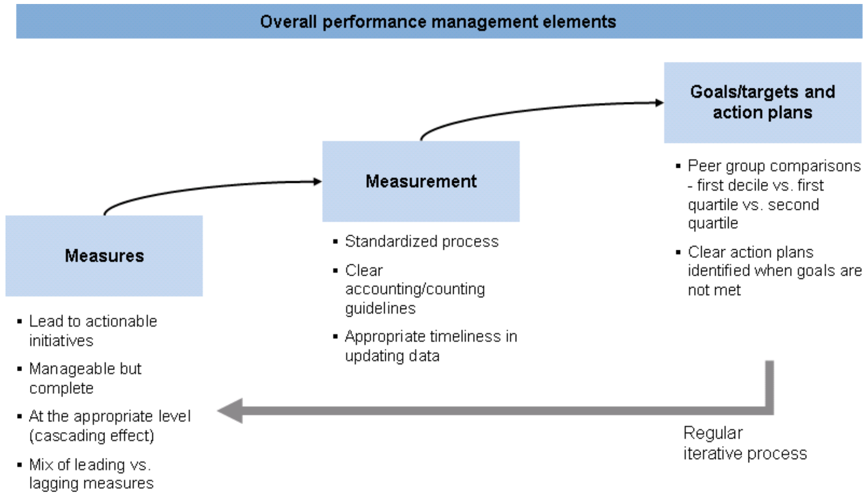
To reduce the burden of measurement, a standardized process would decrease the time and costs necessary to report on the data collected. The process should include clear accounting principles to be strictly followed to ensure data validity at all levels. Regular reporting timelines should be included as part of the process so the data is updated when it needs to be used.

Goals/Targets and action plans

Metrics can be used to track the success of meeting a target, as well as be used to create new targets. These metrics can be used to benchmark against peers and determine areas of opportunity.

Regular iterative process

Each iterative process will re-examine the usefulness of each metric being measured. Some metrics will be removed while others will be added to fit the needs of the current corporate strategy and goals.



Addressing the main drivers of productivity

There are three main drivers of productivity; reducing unproductive time, increasing efficiency of productive time and reducing unnecessary activities.

These levers should be addressed for direct as well as indirect labor (support and admin). When creating the metrics using a 'fully burdened' cost will help to ensure that improvements in the indirect portion of an activity are seen in the metric over time.

Reducing unproductive time

Targeting unnecessary meetings and trainings which are not beneficial will free the time in which the meeting or training participants are not being productive. Training times can be reduced by consolidating training sessions. Unproductive standard meetings can be removed.

Improving scheduling to reduce dead times. These dead times include the time in between jobs and the time at the end-of-day. Improving vacation scheduling to incentivize taking vacations during non-peak work times will create a larger available workforce during peak times.

Building better work planning tools to reduce travel times. These tools could reduce travel time by scheduling more jobs in similar areas together, dispatching the workforce from home instead of coming to yard and having real time traffic information to reduce time spent on the road.

Negotiating for lower minimum bill times will reduce the time that labor is unproductive but still being paid for the job.

Increasing efficiency of productive time

Improving the tools and processes in use during productive time will create an overall increase in productivity. Using more prefabricated construction offsite will allow for faster construction on site when expensive labor needs to be utilized. Technology can be used in planning to allow for more efficient job scheduling. Increasing the use of standardized components would require less training, cheaper procurement and inventory management. Another way of using tools to increase efficiency would be to preload asset location and details onto GPS systems in fleet.

Optimizing working team skill blend reduces the labor cost necessary to complete an activity. Team skill blend can be altered by using mixing more experienced hires with more junior team members (e.g. the apprentice model). Using hiring hall where possible will optimize skill blend because hiring hall is cheaper to use than experienced, often expensive full time staff.

Implement peak shaving through using contractors where applicable to reduce total staff on books required to cover peak work loads.

Align compensation and performance to ensure good audited data and encourage ‘bottom up’ initiatives.

Reducing unnecessary activities

These activities can be reduced by eliminating unnecessary work processes most importantly for indirect costs. Another strategy is to build a strategic contacting strategy by performing activity level benchmarking to determine where activities are under performing a similar panel.

Report Appendix:

- Findings from regulatory bodies
- Additional analysis of costs

Summary of results from Canadian commissions

Comm-issions	Key Findings	Metrics filed regularly		
		Produc-tivity*	Cost**	SQM
British Columbia Utilities Commission	▪ The revenue requirement applications include reliability metrics (SAIDI, SAIFI, CAIDI), factor productivity (# Customers/Network Length), and cost (T+D Capex/T+D line km) ▪ BC Hydro benchmarks reliability through the CEA ▪ Fortis submits an annual review including SQM metrics and general cost of service information	✘	13	29
Alberta Utilities Commission	▪ The general tariff applications include reliability metrics (SAIDI, SAIFI, AIIFR), and cost metrics (O+M spend/gross plant assets) ▪ Rule 002 and Rule 003 detail the service quality filing requirements for annual report	✘	3	24
Saskatchewan Rate Review Panel	▪ SaskPower rate case did not contain metrics ▪ A RFI stated performance metrics would be measured internally by SaskPower but were not collected by SRRP.	✘	✓	✘
Manitoba Public Utilities Board	▪ The *Public Utilities Board Act* has no minimum filing requirements. ▪ The PUB requested independent benchmarking for MH, study is delayed until late 2011 ▪ Manitoba Hydro files an *Electric Board Annual Report* with safety and cost metrics	✘	2	7
Ontario Energy Board	▪ The rate cases contain system reliability metrics, and veg. mgmt. benchmarking study ▪ The *OEB Year Book* and *Electricity Reporting and Record Keeping Requirements* contain service quality metrics and cost metrics filed annually	✘	6	17
Quebec Energy Board	▪ The rate cases contain cost (cost per customer) and service quality metrics (SAIDI, telephone answer rate, telephone abandon rate) ▪ The annual filing requirements include cost, and service quality metrics (safety, reliability)	✘	38	20
Nova Scotia Utilities and Review Board	▪ The rate cases contain cost metrics (OM&G/Customer) and reliability metrics (SAIFI*SAIDI) ▪ A NSPI Rate case contained an operational review called the Kaiser study containing some metrics relating to cost, SQ and productivity (calls handled per agent per day) ▪ An ad hoc independent operational review contained one productivity metric: Calls handled per agent per day	✘	4	6
New Brusnwick Energy and Utilities Board	▪ The rate applications (DISCO, NBSO, NBP) do not contain performance metrics, but do include financial information ▪ The *Electricity Act* does not mandate metrics to be filed	✘	✓	✘

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

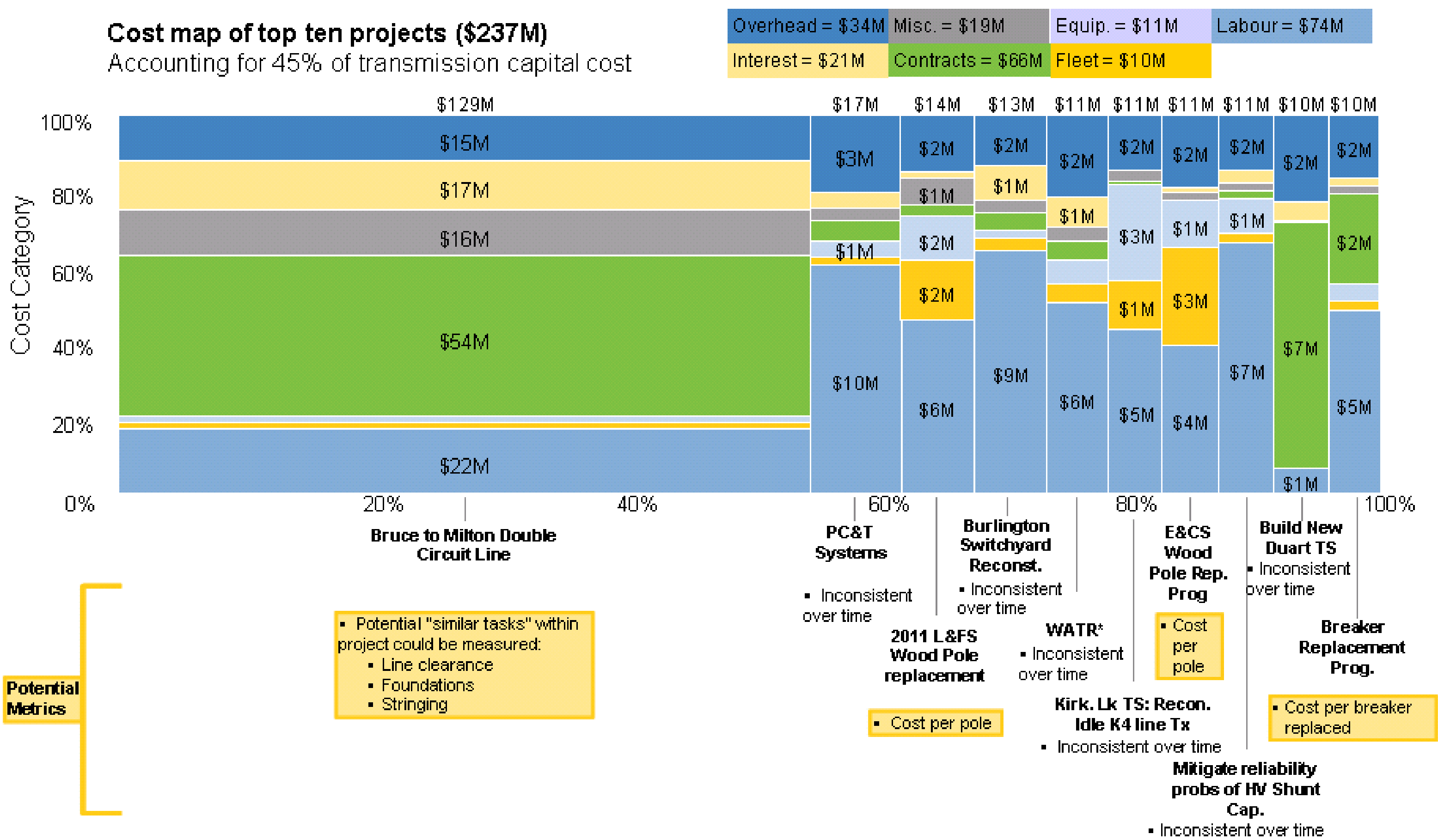
Summary of results from US commissions

Comm-issions	Key Findings	Metrics		
		Produc-tivity*	Cost**	SQM
Massachusetts Department of Public Utilities	▪ *Order 04-116* states annual minimum reporting requirements (CKAIDI, CKAIFI, SAIDI, SAIFI, % Billing Adjustments, and Customer Services guarantees) ▪ Electric and gas utilities in MA are required to file annual service quality reports	✘	✓	19
New York Public Services Commission	▪ The rate cases contain reliability metrics ▪ *NYCRR S. 61* details minimum financial filing requirements for rate cases ▪ Customer service and reliability reports are filed annually with the PSC	✘	✓	13
Pennsylvania Public Utilities Commission	▪ The Pennsylvania Public Utility Code required annual filing of reliability standards ▪ Electric service reliability and quality of service reports are filed each year	✘	✓	16
Michigan Public Services Commission	▪ System performance and power quality reports are filed annually containing service quality metrics (reliability, customer service, % meter reads etc) ▪ The rate cases does not contain performance metrics	✘	✓	13
Public Utilities Commission of Ohio	▪ The minimum filing requirements did not state performance metrics had to be filed ▪ Annual reliability reports are filed annually (SAIDI, SAIFI, CAIDI)	✘	✓	7
Illinois Commerce Commission	▪ No productivity or cost metrics required to be filed ▪ The *Public Utilities Act* and *Electric Supplier Act* detailed filing requirements (SAIFI, CAIFI, CAIDI, customer service survey)	✘	1	8
Connecticut Public Utilities Regulatory Authority	▪ The rate cases contained orders containing call center metrics ▪ Reliability information is required to be filed annually as per the *Connecticut Code*	✘	✓	9
California Public Utilities Commission	▪ The *New Jersey Administration Code* states filing requirements for reliability ▪ The rate cases have customer service metrics	✘	✓	9

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

Transmission capital: Cost map of top ten projects

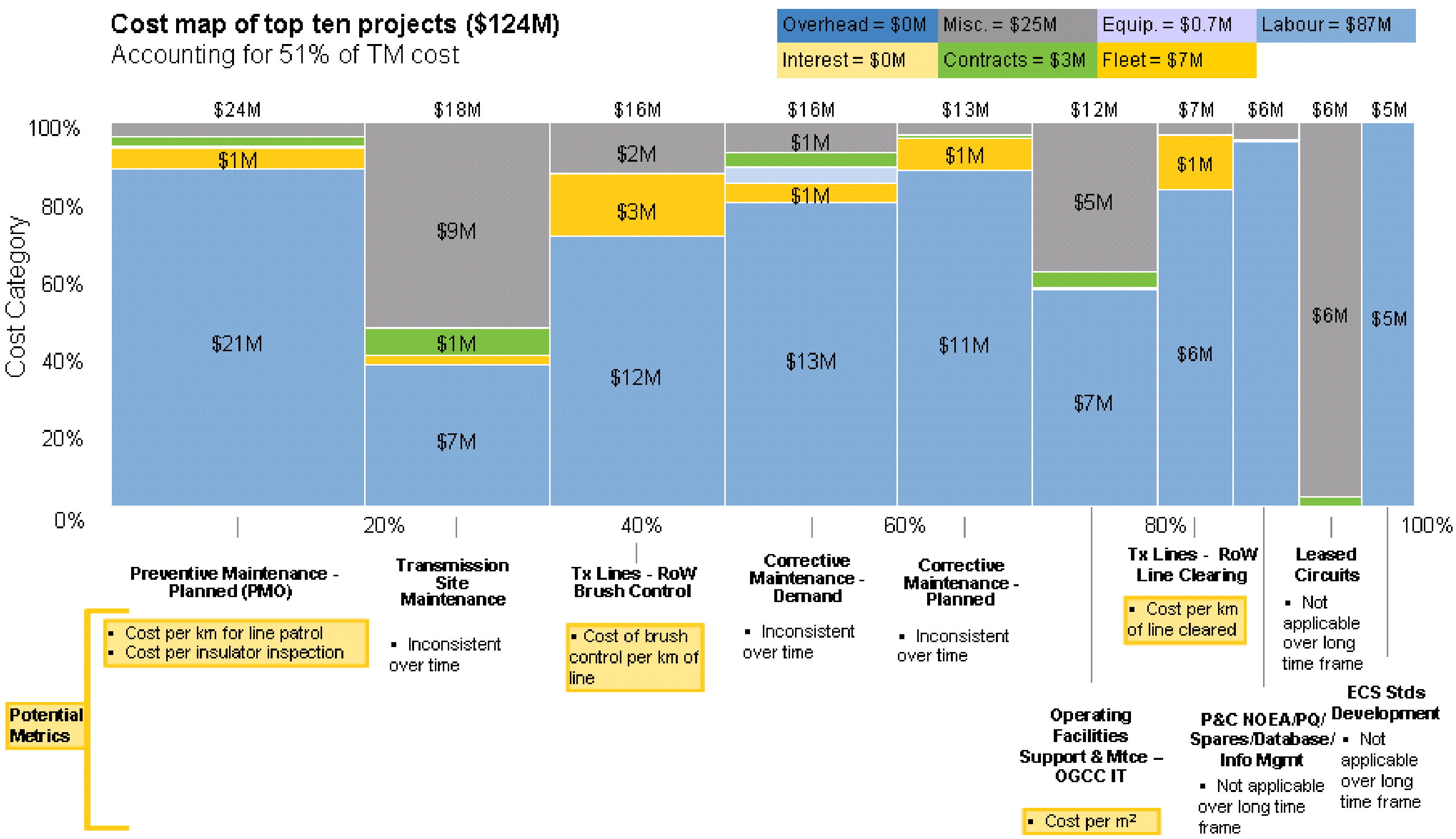
As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Costs are concentrated in a few very large projects. Though these major projects cannot be measured with a single metric, several activities within the project could be potentially measured.



Note: Costs are approximate values, annualized from May 2011. This chart excludes material costs. Total transmission capital cost includes negative and zero cost projects.

Transmission OM&A: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Transmission OM&A is more evenly distributed across the biggest projects than transmission capital, but each project still contains a diverse set of activities.



Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total transmission maintenance cost includes negative and zero cost projects.

Distribution capital: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. For Distribution Capital costs, many are large project related and therefore not measureable over time making them less suitable for tracking.

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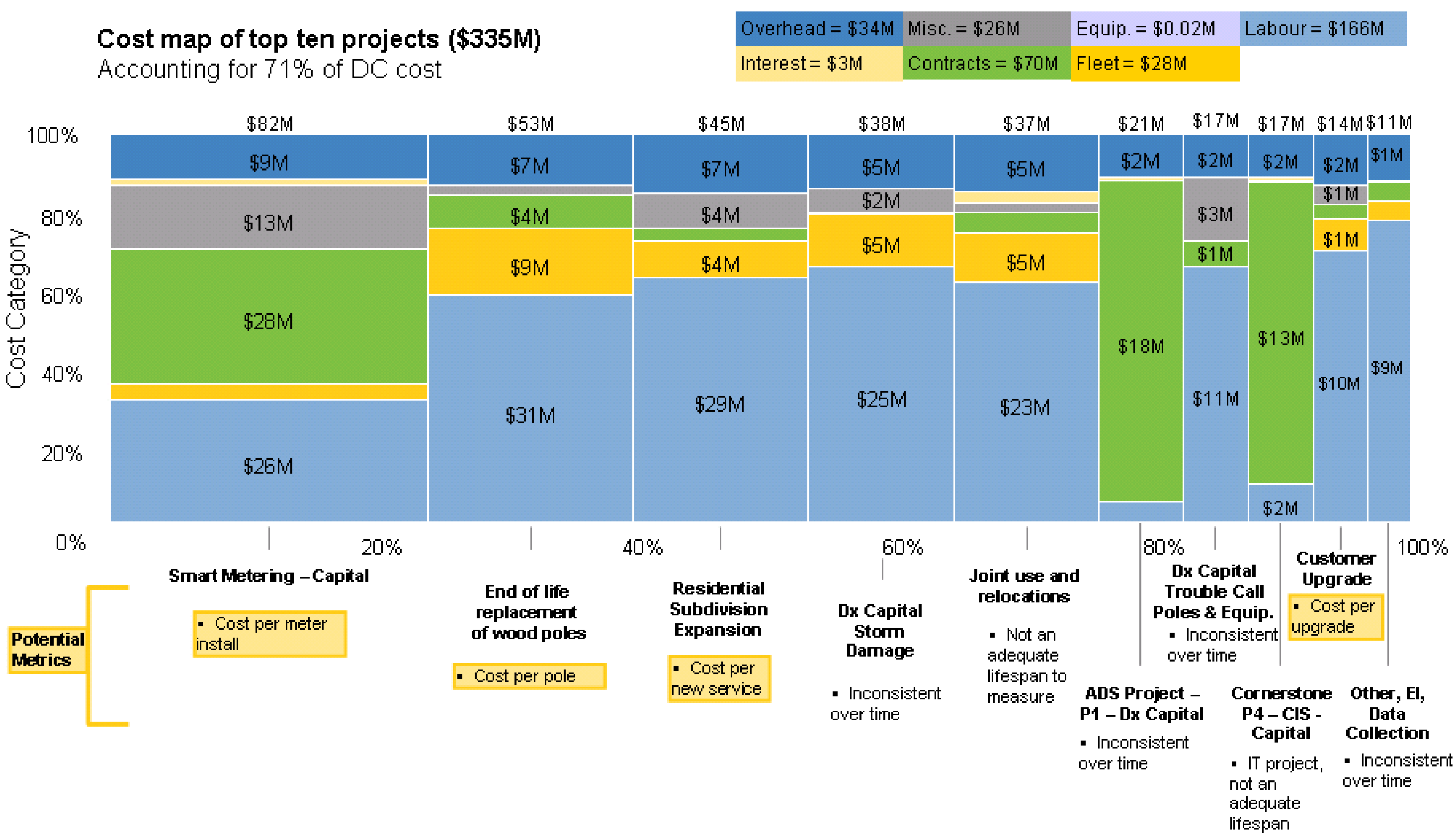

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total distribution capital cost includes negative and zero cost projects.

Distribution OM&A: Cost map of top 10 projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Distribution OM&A has the largest amount of repeatable activities suitable for metrics.

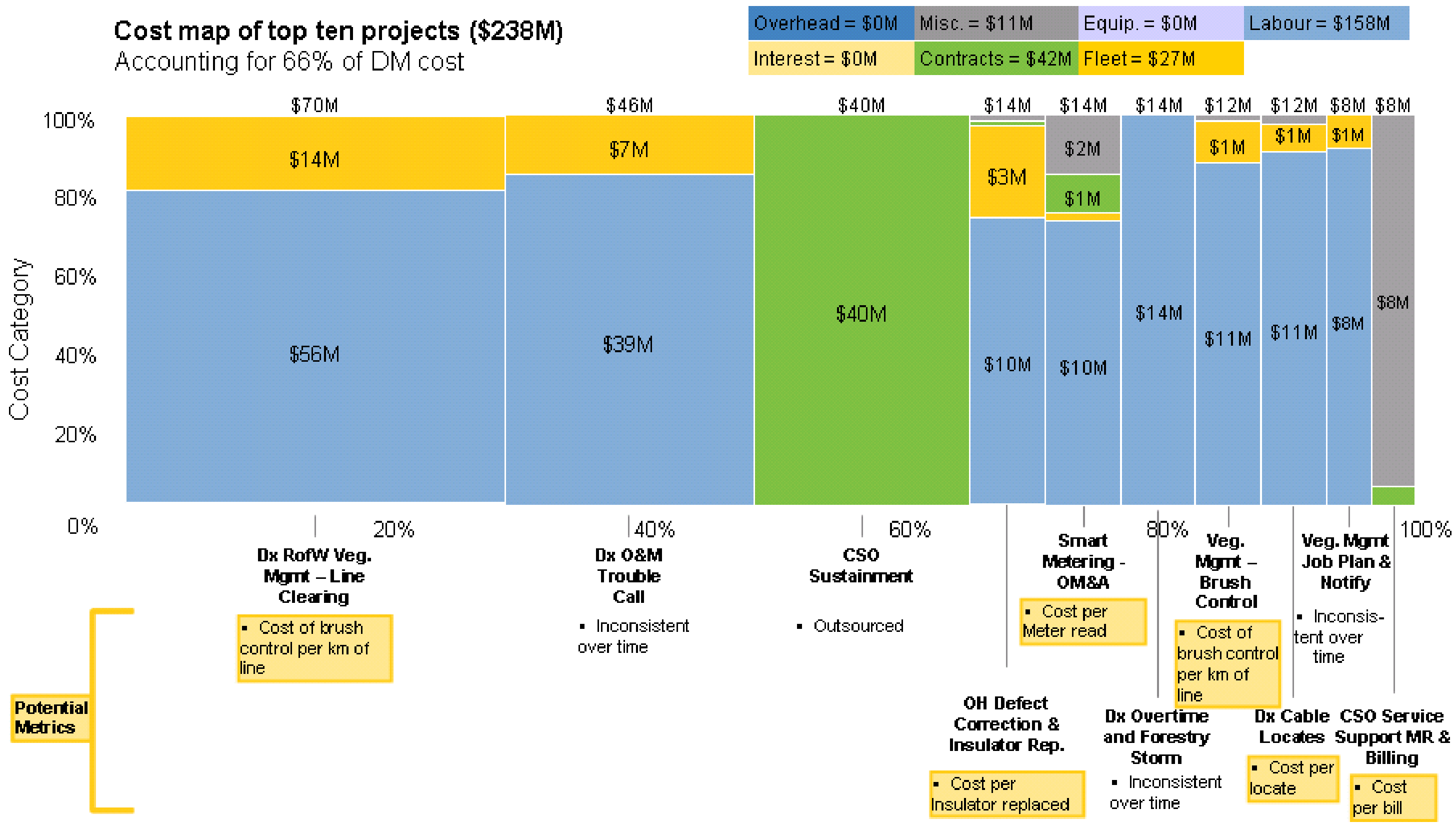

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Figure 1:

Distribution Productivity Savings

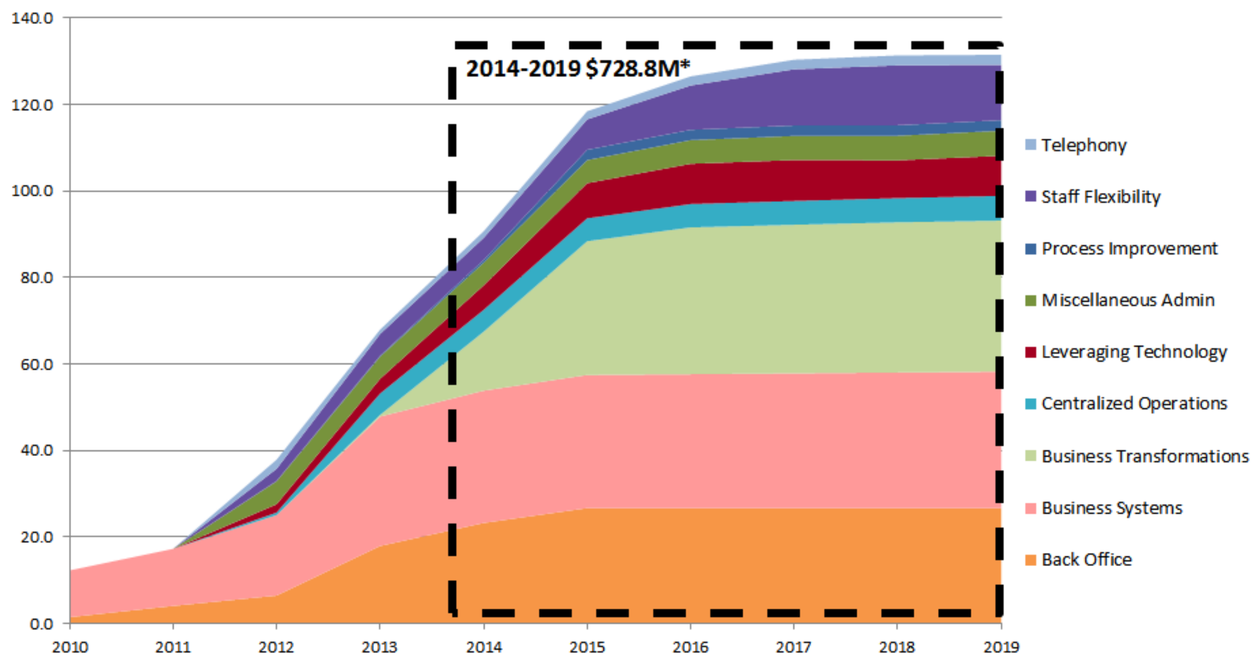

Table 2:

Total Annual Savings - Distribution ($ Million)

Description	Historical				Bridge Year	Test Years					Cumulative
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2014 - 2019
Back Office	1.5	4.1	6.5	18.0	23.3	26.7	26.7	26.7	26.7	26.7	156.9
Business Systems	10.8	13.2	18.6	29.9	30.6	30.8	31.0	31.1	31.3	31.5	186.3
Business Transformations	0.0	0.0	0.0	0.4	13.6	30.9	33.9	34.4	34.7	34.9	182.5
Centralized Operations	0.0	0.0	0.6	5.0	5.0	5.3	5.4	5.5	5.6	5.7	32.6
Leveraging Technology	0.0	0.0	1.9	3.4	5.7	8.1	9.3	9.5	8.7	9.3	50.5
Miscellaneous Admin	0.0	0.0	5.3	5.1	5.2	5.3	5.5	5.6	5.7	5.8	33.0
Process Improvement	0.0	0.0	0.1	0.2	0.6	2.4	2.4	2.4	2.4	2.4	12.7
Staff Flexibility	0.0	0.0	2.8	5.0	5.1	7.0	10.2	13.0	13.8	12.8	62.0
Telephony	0.0	0.0	2.1	1.0	1.5	1.9	2.1	2.2	2.3	2.3	12.3
Total	**12.3**	**17.3**	**37.9**	**68.0**	**90.7**	**118.4**	**126.5**	**130.3**	**131.3**	**131.5**	**728.8**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #42

Issue 2.3 **Does the Custom Application adequately incorporate and reflect the four outcomes identified in the RRFE Report: customer focus, operational effectiveness, public policy responsiveness and financial performance?**

Interrogatory

Reference: **A/T19/S1**

a) Please show the derivation and of the productivity savings shown in Table 1 for years 2013 through 2019.

Response

Please see summary sheet provided below.

Initiative Name	LOB	Category	OMA	CAP	Sus	Dev	Oper	Cus	Com	2013 Actual	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
AIP - Asset Investment Planning	Planning & Operating	Business Transformations	100%	0%					100%	170,496	173,160	177,689	182,246	185,500	188,784	191,654
Regular Head Count Reduction	Corporate	Centralized Operations	100%	0%					100%	4,853,669	4,853,669	5,095,664	5,197,577	5,301,528	5,407,559	5,515,710
Admin Spend Controls	Corporate	Miscellaneous Admin	100%	0%					100%	5,119,362	5,230,362	5,341,362	5,452,362	5,563,362	5,674,362	5,785,362
Initial Training: union pays for basic	Engineering & Construction	Staff Flexibility	100%	0%	63%	35%	2%	0%	0%	150,809	127,410	129,774	133,031	134,905	138,652	140,526
Outsourcing Drawing Backlog	Engineering & Construction	Staff Flexibility	100%	0%	63%	35%	2%	0%	0%	633,011	117,660	117,660	117,660	117,660	117,660	117,660
Electrical Safety Awareness available online	Health, Safety & Environment	Centralized Operations	100%	0%					100%	-	66,600	67,932	69,291	70,676	72,090	73,532
Spills Management training via E Learning	Health, Safety & Environment	Centralized Operations	100%	0%					100%	38,428	39,197	39,981	40,780	41,596	42,428	43,276
Workflow of the Future	ISD	Business Transformations	100%	0%					100%	-	-	-	1,320,811	1,347,227	1,374,172	1,401,655
Cell Contracts	ISD	Telephony	100%	0%					100%	730,940	947,960	1,141,120	1,218,384	1,218,384	1,218,384	1,218,384
Telecom Expense Management (TEM)	ISD	Telephony	100%	0%					100%	265,943	556,144	725,285	888,000	976,800	1,065,600	1,110,000
Process Improvements & BPC	Shared Services	Business Transformations	100%	0%					100%	213,120	213,120	217,382	221,730	226,165	230,688	235,302
HR Pay Project	Shared Services	Business Transformations	100%	0%					100%	-	309,283	1,210,231	1,234,436	1,259,125	1,284,307	1,309,993
Vendor Rebates	Shared Services	Centralized Operations	100%	0%	73%	23%	2%	2%		60,384	88,800	88,800	88,800	88,800	88,800	88,800
Facilities Energy Efficiency Retrofits	Shared Services	Leveraging Technology	100%	0%	100%					11,321	11,100	11,100	11,100	11,100	11,100	11,100
Employee Travel Policy	Shared Services	Leveraging Technology	100%	0%					100%	25,237	24,420	-	-	-	-	-
Project Trailer Purchase	Shared Services	Process Improvement	100%	0%					100%	-	71,040	71,040	71,040	71,040	71,040	71,040
Manage Stations Work for Facilities	Shared Services	Staff Flexibility	100%	0%	100%					1,738,260	1,738,260	-	-	-	-	-
Fleet Mechanic Reduction	Shared Services	Staff Flexibility	100%	0%	73%	23%	2%	2%		445,776	666,000	666,000	666,000	666,000	666,000	666,000
Work Program Optimization (TSOGs)	Stations Services	Leveraging Technology	100%	0%	96%	1%	3%	0%		-	973,966	965,499	1,433,654	1,358,413	1,387,167	1,691,823
SMNO - Smart Meter Network Operating	Stations Services	Leveraging Technology	100%	0%	95%	0%	4%	0%		-	-	-	221,730	447,895	678,583	913,884
Maintain Stock of Regularly Used Items	Stations Services	Process Improvement	100%	0%	95%	0%	4%	0%		113,478	155,400	158,508	161,678	164,912	168,210	171,574
TWHQ - Stations	Stations Services	Staff Flexibility	100%	0%	95%	0%	4%	0%		952,840	177,600	181,152	184,775	188,471	192,240	196,085
Inhouse Retorques on Light Vehicles	Stations Services	Staff Flexibility	100%	0%	95%	0%	4%	0%		41,887	39,960	39,960	39,960	39,960	39,960	39,960
Cornerstone Ph1, 2	Corporate	Business Systems	42%	58%					100%	29,917,623	30,579,471	30,762,912	30,950,022	31,140,874	31,335,544	31,534,106
Standards Development for Design	Engineering & Construction	Leveraging Technology	0%	100%	63%	35%	2%	0%	0%	144,250	144,250	144,250	144,250	144,250	144,250	144,250
Smart MFA spend	Engineering & Construction	Process Improvement	0%	100%	63%	35%	2%	0%	0%	88,949	120,294	120,294	120,294	120,294	120,294	120,294
AA	Planning & Operating	Business Transformations	44%	56%					100%	-	2,634,745	3,918,248	4,093,431	4,327,007	4,502,190	4,502,190
Facilities & Real Estate Outsourcing	Shared Services	Staff Flexibility	100%	0%					100%	-	-	3,600,000	3,600,000	3,600,000	3,600,000	3,600,000
Inergi Contract Extension	Shared Services	Back Office	100%	0%					100%	17,958,000	23,287,000	-	-	-	-	-
Contract Replacement	Shared Services	Back Office	100%	0%					100%	-	-	26,718,000	26,718,000	26,718,000	26,718,000	26,718,000
CIS	Customer Service	Business Transformations	100%	0%					100%	-	10,300,000	19,785,000	19,785,000	19,785,000	19,785,000	19,785,000
Advanced Distribution System (ADS) Phase 1	Provincial Lines & Forestry	Business Transformations	100%	0%					100%	-	-	5,615,000	7,099,060	7,224,321	7,355,808	7,490,544
Usage of feller bunchers	Provincial Lines & Forestry	Leveraging Technology	100%	0%	100%					3,218,007	3,000,000	4,500,000	4,500,000	4,500,000	3,000,000	3,000,000
Field Meter Reads	Provincial Lines & Forestry	Process Improvement	100%	0%				100%		-	827	1,731,763	1,748,791	1,761,331	1,770,769	1,777,930
Forestry ACA incorporated into Lines inspections	Provincial Lines & Forestry	Staff Flexibility	100%	0%	100%					892,252	901,175	946,590	946,590	946,590	946,590	946,590
Labour Mix and Misc Productivity Improvements	Provincial Lines & Forestry	Staff Flexibility	100%	0%	100%					-	-	-	1,500,000	3,400,000	3,400,000	1,500,000
Reduce Cables Locates	Provincial Lines & Forestry	Staff Flexibility	100%	0%	100%					180,000	1,345,418	1,345,418	3,045,418	3,895,418	4,745,418	5,595,418
Distribution transformer refubishment	Shared Services	Process Improvement	0%	100%	100%					-	300,000	300,000	300,000	300,000	300,000	300,000
IMDS	Stations Services	Leveraging Technology	0%	100%	95%	0%	4%	0%		-	1,500,000	2,500,000	3,000,000	3,000,000	3,500,000	3,500,000
Total										**67,964,040**	**90,694,288**	**118,433,612**	**126,505,900**	**130,342,603**	**131,341,646**	**131,507,642**

Ontario Energy Board (Board Staff) INTERROGATORY #11

Issue 2.2 Does Hydro One Distribution's Custom Application promote and incent acceptable outcomes for existing and future customers (including, for example, cost control, system reliability, service quality, bill impacts)?

Interrogatory

Ref: 1. RRFE Report, October 18, 2012
2. Exhibit A

Preamble:
At page 12 of the RRFE Report, the Board states: "To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken in to account in establishing the rate adjustment mechanisms applicable to each rate method through the X-factor."

a) In the absence of an X-factor, what process is Hydro One proposing to ensure that benefits are appropriately shared through the rate term between Hydro One and its customers?

b) How will Hydro One share any additional productivity and/or total cost efficiency gains it achieves over the term of the plan with its customers?

Response

a) Hydro One's proposal does ensure benefits are appropriately shared throughout the rate term. The forecasted productivity savings embedded in Hydro One's revenue requirement calculation are described in Exhibit A, Tab 19, Schedule 1. For the ratepayer, the requested rate increase has been lowered by the amount of these productivity savings. Ratepayers' receipt of the forecasted monetary benefit is guaranteed, regardless of whether it is realized, and it is received throughout the rate term. In contrast, Hydro One's shareholder bears the downside risk of Hydro One failing to realize these savings because this failure will directly impact its return on equity. Offsetting this shareholder risk is the potential to benefit in the event that additional efficiencies are realized. This should incent Hydro One to realize the forecasted cost savings from efficiencies at a minimum.

b) Given that its forecasted productivity savings are ambitious, Hydro One does not expect to achieve additional efficiency gains over the 5-year term. Any unexpected, additional gains may be redirected into work programs and projects which benefit the customer.

School Energy Coalition (SEC) INTERROGATORY #47

Issue 4.4 Is the compensation strategy for 2015-2019 appropriate and does it result in reasonable compensation costs?

Interrogatory

Reference: Exhibit C1/Tab 3/Schedule 2/Attachment 1/p.6-7

Please explain why only four other Ontario distributors were invited to participate in the compensation benchmarking survey. Please explain why it was not more appropriate to benchmarking the Applicant's compensation with all the other distributors in the province.

Response

The benchmarking study was designed to gather and analyze total compensation data from a panel of organizations with which Hydro One competes for talent. A single panel of organizations was used to benchmark the Hydro One employee groups, in accordance with the selection criteria described below, to facililitate cross-group comparisons and to increase the survey efficiency.

Mercer selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer establishes limits of 33% to 300% of the scope criteria for the organization we are analyzing.

For the purposes of this study, Mercer considered all organizations with limits of 33% to 300% from a pool of organizations in the following industry segments:

- Electric utilities, multi-utilities, generators, and gas utilities industries in Canada
- Local Distribution Companies ("LDCs") in Ontario
- Other comparable regulated businesses (i.e., integrated telecommunication services, railroads etc.)

These industry segments were indicated by Hydro One as areas that reasonably reflect the same labour market that Hydro One competes for talent in.

Some organizations were included in the analysis despite falling below the 33% of revenue threshold value. These organizations were primarily Ontario based local distribution companies that are seen as important benchmarks by stakeholders. Specifically these organizations were Enersource, Horizon Utilities, Powerstream, and Toronto Hydro. Two other Ontario LDC's were invited to participate, Hydro Ottawa and Veridian, however both declined because of internal resource constraints.

School Energy Coalition (SEC) INTERROGATORY #43

Issue 4.4 **Is the compensation strategy for 2015-2019 appropriate and does it result in reasonable compensation costs?**

Interrogatory

Reference: Exhibit C1/Tab 3/Schedule 1/p.10

Please provide all assumptions the Applicant is making for the purposes of this application for future collective agreements between itself and the Power Workers' Union and Society of Energy Professionals.

Response

It is assumed that there will be a continued focus on cost containment and increased flexibility as Hydro One enters collective bargaining in 2015 and 2016. It is premature to elaborate on specifics at this time.

Rating Report

Report Date:
April 10, 2014

Previous Report:
October 10, 2013

Insight beyond the rating.

Hydro One Inc.

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The Company

Hydro One Inc. is the largest regulated electric transmission and distribution utility in Ontario, serving more than 97% of the province's transmission throughput. The Company also owns a fibre-optic network across most of Ontario. Hydro One is wholly owned by the Province of Ontario (rated AA (low)).

Commercial Paper

Authorized Limit of $1.0 Billion

Recent Actions

March 8, 2013
Confirmed

Rating

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating Update

DBRS has confirmed the Issuer Rating and the Senior Unsecured Debentures rating of Hydro One Inc. (Hydro One or the Company) at A (high), and the Commercial Paper rating at R-1 (middle). All trends are Stable. The ratings confirmation is underpinned by the Company's low business risk profile, a supportive regulatory framework in Ontario and a strong financial profile sustained by stable earnings and cash flows. The Stable trend assumes that the regulatory regime under the Renewed Regulatory Framework will continue to remain reasonable, allowing the Company to earn adequate returns and pass through prudently incurred costs on a timely basis.

Hydro One's business risk profile is indicative of an A (high) rating as the Company operates in an extensive franchise area, with regulated transmission and distribution businesses in Ontario accounting for substantially all its earnings. DBRS continues to view the regulatory framework in Ontario as reasonable for regulated transmission and distribution operators (refer to Assessment of Hydro One's Regulatory Environment on Page 8). In late 2013, the Ontario Energy Board (OEB) released a final report on its Renewed Regulatory Framework, setting out policies and approaches to the rate adjustment parameters for incentive rate (IR) setting and the benchmarking of total cost performance. DBRS views the parameters of the Custom Incentive Rate-setting option under the Renewed Regulatory Framework as modestly positive for Hydro One's distribution business (35% of EBIT) as it provides greater clarity for recovery and pass through of capital costs to ratepayers, and it reduces pressure on utilities to meet operating efficiency targets. However, this is somewhat offset by the modestly higher regulatory lag under the Custom IR regime, which the Company will operate under, as it has a minimum term of five years as compared with the previous three-year rate setting process. It also remains to be seen how operating expenses and capex will be scrutinized as the Company proceeds under the Custom IR framework.

Hydro One's financial profile reflects an A (high) rating as key credit metrics have remained in the upper range of the "A" rating category. Hydro One's ratings are on a stand-alone basis but are constrained by the rating of the Province of Ontario (the Province; rated AA (low)), which acts as a ceiling. DBRS assumes that Hydro One's rate base will continue to grow and provide incremental cash flow to fund the majority of capex and maintain debt-to-capital at around 55%, with minimal regulatory lag and no significant cost-overruns.

Rating Considerations

Strengths	Challenges
(1) Low business risk	(1) High level of planned capex
(2) Strong financial profile	(2) Project construction risk
(3) Extensive franchise area	(3) Significant external financing requirements
(4) Indirect support from the province of Ontario	(4) Limited access to equity markets

Financial Information

Hydro One Inc.	For the year ended December 31				
(CAD millions where applicable)	2013	2012	2011	2010	2009
EBIT gross interest coverage (times)	3.06	2.91	2.75	2.42	2.23
Total debt in capital structure	55.1%	55.5%	55.5%	56.5%	56.2%
Cash flow/Total debt	15.3%	15.4%	14.6%	13.9%	13.8%
(Cash flow-dividends)/Capex (times)	0.83	0.65	0.70	0.67	0.50
Net income before non-recurring items	795	736	632	579	470
Cash flow from operations	1,390	1,313	1,176	1,080	964

1-Staff-8

Attachment 1

2014 - 2019 HYDRO ONE BUSINESS PLAN INSTRUCTIONS

9.0 INCOME & CAPITAL TAX RATES

	2013	2014	2015	2016	2017	2018	2019
Federal Tax Rate	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Provincial Rate	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Total Statutory Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Capital Tax Rate	NIL	NIL	NIL	NIL	NIL	NIL	NIL

Contact Selma Yam (416) 345-6827 for further details or questions on tax rates.

10.0 BENEFIT COSTS RATES (PAYROLL BURDEN)

The forecast Hydro One burden rates for each subsidiary are shown below. Note that the dollar amounts and a more detailed breakdown are available upon request.

US GAAP

Company	Category	2013	2014	2015	2016	2017	2018	2019
Hydro One Inc	Non-Regular Staff							
	% of total earnings*	3.04%	3.06%	3.09%	3.12%	3.15%	3.15%	3.15%
	Regular Staff							
	% of total earnings*	3.04%	3.06%	3.09%	3.12%	3.15%	3.15%	3.15%
	% of base pensionable earnings**	12.43%	12.56%	12.70%	12.96%	13.28%	13.28%	13.28%
	Pension							
	% of base pensionable earnings	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%
Networks	Non-Regular Staff							
	% of total earnings*	6.51%	6.61%	6.81%	6.84%	6.93%	6.93%	6.93%
	Regular Staff							
	% of total earnings*	6.51%	6.61%	6.81%	6.84%	6.93%	6.93%	6.93%
	% of base pensionable earnings**	28.45%	28.83%	29.24%	29.93%	30.69%	30.69%	30.69%
	% of base pensionable earnings***	0.39%	0.39%	0.39%	0.39%	0.39%	0.39%	0.39%
		28.84%	**29.22%**	**29.63%**	**30.32%**	**31.08%**	**31.08%**	**31.08%**
	Pension							
	% of base pensionable earnings	31.11%	31.11%	31.11%	31.11%	31.11%	31.11%	31.11%
Remote Comm.	Non-Regular Staff							
	% of total earnings*	5.87%	5.93%	6.04%	6.14%	6.25%	6.25%	6.25%
	Regular Staff							
	% of total earnings*	5.87%	5.93%	6.04%	6.14%	6.25%	6.25%	6.25%

Company	Category	2013	2014	2015	2016	2017	2018	2019
	% of base pensionable earnings**	27.04%	27.31%	27.63%	28.23%	28.92%	28.92%	28.92%
	Pension % of base pensionable earnings	30.86%	30.84%	30.84%	30.84%	30.84%	30.84%	30.84%
Telecom	Non-Regular Staff % of total earnings*	5.19%	5.24%	5.33%	5.41%	5.51%	5.51%	5.51%
	Regular Staff % of total earnings*	5.19%	5.24%	5.33%	5.41%	5.51%	5.51%	5.51%
	% of base pensionable earnings**	17.21%	17.38%	17.58%	18.06%	18.58%	18.58%	18.58%
	Pension % of base pensionable earnings	23.85%	23.85%	23.85%	23.85%	23.85%	23.85%	23.85%

*CPP, Emp. Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, Ontario Health Premiums (OHP)
*** OPRB – Inergi

- Base Pensionable Earnings includes pensionable bonus.
- Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.

Contact Cathy Sewell (416) 345-5772 for further details or questions.