Building Owners and Managers Association Toronto Interrogatory # 10

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02-01 Page: 17

Interrogatory:

Please explain how the GDPIPI-Canada differs from the CPI.

Response:

The GDP-IPI is an index that compares the nominal GDP to real GDP for a given year. It includes all domestically produced goods and services in the country. This makes it far more comprehensive than the CPI, because the CPI measures the price changes using a specific selection (or basket) of categories of consumer goods and services. Each good is weighted based the average household expenditure of that good within the selection. However, lots of other goods are not included in the CPI selection, such as machinery. This makes the GDP-IPI more appropriate for measuring the input price inflation of the electric distribution industry relative to the CPI.

Building Owners and Managers Association Toronto Interrogatory # 11

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02-01 Page: 23

Interrogatory:

Please explain what is meant by a "triangulated weighted average".

Response:

A triangulated weighted average is used within the study to estimate the average construction prices of the net plant value in the capital benchmark year of the study. For this study, that year is 2002. PSE used the 2002 net plant value, and needs to convert that to a capital quantity number. To do this, we need to divide the net plant by the estimated asset prices embedded within that net plant value. Since the net plant is built up over a large number of years, we calculate a weighted average of those asset prices. The weights are the sum of the past 40 years estimated remaining plant. For instance, if our benchmark is 2002, we assume that in 2001 39/40 (or 97.5%) of the plant put in service in 2001 remains in 2002. In 2000, the ratio is 38/40, and so forth to 1962 (40 years before 2002). We then sum these weights for all 40 years, and take the ratio of the remaining plant in each year to the sum. This serves as the basis for the asset price embedded in the 2002 net plant value.

Building Owners and Managers Association Toronto Interrogatory # 61

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-01-04 Page: 9

Interrogatory:
How have contingencies and escalation allowances been refined?

Response:
Please refer to Exhibit I-24-Staff-121, part a).

Building Owners and Managers Association Toronto Interrogatory # 66

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-01-05 Page: 3-4

Interrogatory:

a) What is a total cost economic model? Please explain fully.

b) Prudent changes to the model co-efficient estimate were made due to the addition of:
   i. the 2016 data;
   ii. the 2017-2022 forecasts.

   Given that the PSE proposes the lower stretch factor of 0.45 based on the addition of 2016 actuals (rather than 0.6 that PSE had recommended), does the company plan to provide actual vs. predicted performance relative to the benchmark for each year after each year of the five year period? Would that number be used to select the stretch factor for the next year?

c) Does the US data contain forecasts of costs over the following five years? Please discuss.

d) Why is the comparison the percentage difference of Hydro One's actual costs and the predicted costs, rather than the direct percentage comparison of actual and predicted costs? Why is it the "convention within the industry"?

e) If forecasts are not included for the benchmarked companies, what assumptions are made to construct them? What are the problems with a future exercise?

f) What impact of using forecasts of costs, as well as actual costs?

g) Please provide a list of the utilities chosen as the benchmark. How many of them:
   i. have almost the same number of customers as Hydro One Distribution;
   ii. have the same urban-rural split as Hydro One Distribution;
   iii. is the benchmark made up of all the 350 utilities or just a subset of them; if the latter, describe the subset;

(i) are they all electric utilities; what percentage are gas or combination utilities?

Response:

a) Please refer to Exhibit A, Tab 3, Schedule 2, Attachment 2, Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022), pp. 8 to 17.

b) Please refer to Exhibit I-8-Staff-022.

c) No.

d) PSE cannot answer why it is the convention within the industry. However, calculating the percentage difference logarithmically does have an advantage when one is unsure what the denominator should be for the arithmetic approach. For example, if a person has one apple and then gets another apple, the increase was 100%, which is calculated arithmetically by adding one apple and dividing by the original apple. However, if Jack has one apple and Jill has two apples, what is the difference in the apples that Jack and Jill have? If Jack's one apple serves as the denominator then the difference is 100%. However, if Jill's two apples serves as the denominator, the difference is 50% (1/2). The logarithmic approach essentially takes the middle approach. The natural log of two divided by one equals 69.3%, and the natural log of one divided by two equals -69.3%. The answer is the same in both directions. In benchmarking, this becomes relevant because when we compare the actual total costs to predicted total costs we get the same answer (but with the opposite sign) as when we instead compared predicted costs to actual costs. The reference point no longer matters in the answer.

e) The model is estimated using the historical data, those parameter estimates are then used to forecast the predicted values for Hydro One into the future. None of the sampled utilities have observations beyond 2015. This does present the issue that the industry and benchmark sample could change performance in future years. PSE does not dispute that updating the benchmarks in the future using newly available data would be better. However, the increased effort and low chance of changing the stretch factor recommendation may not warrant the increased annual accuracy for one distributor.

f) PSE is unsure of the intent of the question.

g) For the sample list please see the response to Exhibit I-10-Staff-040. PSE examined the year 2010 to answer the sub-questions. The working papers attachments for Exhibit I-8-Staff-023, which are available subject to a confidentiality agreement, can also be used to extend this analysis. In 2010 there are 13 utilities that have a number of customers within 200,000 of Hydro One. Hydro One has 1,221,970 total customers in 2010. We did not examine the urban/rural split explicitly in this research. However, if we examine the percent artificial surface variable as a measure of "urban," we see there are several utilities that "surround" Hydro One's value of 0.06%. There are 12 other utilities in 2010 that have the value of 0.06%. There are 29 utilities that have either a 0.05% or a 0.07% value in 2010. If we look at the square kilometers per customer variable as a proxy for "rural-ness," we also see Hydro One is surrounded by similar utilities in this respect. Hydro One's value is 0.79 in 2010. There are 11 utilities that are 0.2 or less below that value, and 6 utilities that are 0.2 or less above that value in 2010.

The econometric model (and thus the benchmark) is estimated using all 380 utilities that are included in the sample. This number excludes Hydro One, which is excluded from the dataset when estimating the model that forms Hydro One's total cost benchmark value. The sample is all electric utilities, with some "combination" utilities included (gas and electric). In 2010, there were 28 gas and electric combination utilities and 344 electric-only utilities. Thus approximately 7.5% of the sample in 2010 consists of combination utilities.

Building Owners and Managers Association Toronto Interrogatory # 79

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

2016 Sector-Wide Consolidated Scorecards of Electricity Distributors Page: 39; Cost Control

Interrogatory:

Of the level 5 designation in this section, PSE level 4 for stretch target purposes.

Response:

This interrogatory poses no question.

Building Owners and Managers Association Toronto Interrogatory # 82

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-05-01 Page: 8

Interrogatory:
a) Please explain why there is no target improvement in utility's total cost per customer and total cost per km of line. What is meant by the footnote re: PEG on p7?

b) Schedule 2: Please explain why HONI proposes a stretch factor of 0.45 when, applying the PEG Analysis, the stretch factor should be 0.60.

Response:
a) For an explanation on why there are no targets for PEG-derived total cost per customer and total cost per kilometer of line measures in the Cost Control Performance Category, please refer to Exhibit A, Tab 5, Schedule 1, Section 4.7 Cost Control Efficiency Assessment, p. 39, lines 9-12 and p. 40, lines 1-6. As noted in lines 4-10 and 21-22 on p.41, the Company developed its own measures to track OM&A dollars per customer and OM&A dollars per kilometer of line. The measures and their associated targets are presented in Exhibit Q, Tab 1, Schedule, p. 20.

   The Electricity Distributor Scorecard in Exhibit A, Tab 5, Schedule 1, p.7, Figure 1, along with the footnotes, is produced by the OEB. Footnote #3 indicates that the measures in the Cost Control Performance Category resulted from the benchmarking analysis conducted by PEG using annual RRR filings.

b) The proposal to use a productivity factor of 0.45 is discussed in Exhibit A, Tab 3, Schedule 2, p.4 and in additional detail in in Exhibit A, Tab 3, Schedule 2, Attachment 2, Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022).

Building Owners and Managers Association Toronto Interrogatory # 88

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-07-01 Page: 1

Interrogatory:

a) When does HONI expect OM&A savings will gain forecasted savings? Please explain what Table 4 is intended to show.

b) Are the proposed new rate classes for Norfolk and Haldimand HONI's rate classes, or separate rate class for both NPDI and HONI? Please explain what is meant by the last sentence on p9. Please provide the numbers to support the assertion, and the impact of the proposed remedy, that is proposed 2021 common rates reflecting the combined costs to serve both utilities.

Response:

a) Table 4 is intended to show the last approved OM&A for each of the Acquired Utilities, actual OM&A for 2014 to 2016, and forecast OM&A for 2017 and 2018. It illustrates the incremental costs to serve the acquired customers. The 2018 forecast costs are the basis for applying the Inflation less Productivity factor to determine the OM&A that will be added to Hydro One Distribution's 2021 revenue requirement to service both legacy and acquired customers.

b) The new acquired rate classes are Hydro One rate classes into which residential, GS<50kW and GS>50kW customers from the acquired utilities (Norfolk, Haldimand and Woodstock) will be moved. The last sentence on page 9 refers to the fact that any rates proposed for just Norfolk customers in 2020 would subsequently be replaced by new rates in 2021 that reflect the combined cost-to-serve both Norfolk and Haldimand customers. While Hydro One does not have specific numbers to quantify the differences in rates, it is clear that establishing a set of rates that would only be in place for 1 year and subsequently replaced by rates calculated under a different set of cost allocation assumptions, would be confusing and frustrating for customers.

Building Owners and Managers Association Toronto Interrogatory # 144

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page: 6

Interrogatory:

The rates referred to in the third bullet on p2 are the rates that are derived from the application of the revenue cap I-X formula to the test year (2018) and each subsequent year. Please explain line 7 of Table 1, the productivity factor is not the 0.45% stretch factor meant to be applied to the revenue.

Response:

The 3rd bullet point on page two of the referenced Exhibit discusses the elimination of the Seasonal customer class. Hydro One is unclear how this reference ties with Table 1.

As noted on page 4 of Exhibit A, Tab 3, Schedule 2, the productivity factor "X" in Hydro One's proposed Revenue Cap Index is equal to the sum of an industry total factor productivity measure (0%) and a stretch factor (0.45%). It is applied to the capital related revenue requirement shown on line 6 of Table 1 consistent with the OEB's findings in its decision on the Custom IR proceeding for Toronto Hydro- Electric System Ltd. (EB-2014-0016). In that decision, the OEB stated that the stretch factor should apply to total costs (i.e. both capital and OM&A).

Consumers Council of Canada Interrogatory # 10

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page 1

Interrogatory:

HON is applying for a Revenue Cap Index with a Custom Capital Factor. What other approaches were considered by HON? Why were they rejected? Did HON use external consultants in developing the Rate Plan? If so, please provide any studies produced by those consultants

Response:

Hydro One reviewed the rate-setting options available to distributors under the RRF in conjunction with other regulatory mechanisms such as the ACM/ICM and determined that the Custom IR method was required to meet Hydro One's operational requirements. As noted on page 2 of Exhibit A, Tab 3, Schedule 2, Hydro One based its RCI on the methodology approved by the OEB for Toronto Hydro-Electric System Limited in EB-2014-0016. Hydro One reviewed the Custom IR mechanisms that were approved by the OEB for other Ontario utilities and determined that the OEB-approved methodology for Toronto Hydro was most consistent with the guidance provided by the OEB in its Handbook for Utility Rate Applications. Hydro One did not use external consultants in developing its Revenue Cap Index.

Consumers Council of Canada Interrogatory # 11

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-01 Page 26

Interrogatory:

Please recast Table 9 – Summary of Distribution Capital and OM&A Expenditures – and include a column that sets out the Original Plan B. Please provide a variance analysis that explains the difference between the Original Plan B and the Modified Plan B.

Response:

The updated table 9, is as follows. The additional columns "Forecast (planned) – Plan B, are inserted at the end (far right).

	Historical (previous plan and actual)											Forecast (planned)					Forecast (planned) - Plan B				
	2013 [1]	2014 [1]	2015			2016			2017 Bridge [2]			2018 Test	2019 Test	2020 Test	2021 Test	2022 Test	2018 Test	2019 Test	2020 Test	2021 Test [4]	2022 Test [4]
	Plan	Plan	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var										
CATEGORY	$M	$M	$M		%	$M		%	$M		%	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0	156.6	159.7	162.9	168.1	172.2
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1	293.2	317.3	336.8	356.3	449.9
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5	78.0	83.4	83.9	77.6	68.4
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3	149.0	187.1	135.8	133.4	136.6	157.2	182.1	129.7	128.1	131.0
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)	633.9	756.8	719.0	740.7	827.2	685.0	742.4	713.3	730.1	821.5
System OM&A [3]	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)	584.8	593.3	601.9	621.4	630.4	584.8	593.3	601.9	621.4	630.4

1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.
2) Bridge year 2017 is a forecast as of end of 2016
3) System OM&A values include all Operations, Maintenance and Administration expenses.
4) 2021& 2022 includes funding for LDC's as per filed

The variance analysis between Plan B and Plan B-modified is as follows:

Investment Description	**2018**	**2019**	**2020**	**2021**	**2022**
Transport and Work Equipment (TWE) Capital Requirements	-4	0	0	0	0
Pole Replacement	-22	0	0	0	0
Large Sustainment Initiatives	-9	0	0	0	0
DS Station Refurbishment Program	-14	0	0	0	0
Dx Facility Accommodation & Improvements	-4	0	0	0	0
C&I Customers - Demand to Interval	-1	1	0	0	0
C&I Customers - First Fuel	-2	0	2	1	0
Immaterial Adjustments over 70+ investments	5	13	4	9	6
Total	**-51**	**14**	**6**	**11**	**6**

Canadian Manufacturers & Exporters Interrogatory # 1

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Updated

Interrogatory:

a) For the 5 bullet points shown on pages 2 & 3, please explain how Hydro One would address each of the points if the OEB were to approve a price cap plan rather than the proposed revenue cap plan.

b) Please explain how the need to update the cost of capital parameters in 2021 to reflect estimated changes in the industry and load forecast over the term are related to the proposal to integrate the Acquired Utilities.

c) Please provide a detailed list and description for each mid-term review component that is being proposed by Hydro One.

Response:

a) See Hydro One's response to Exhibit I-7-VECC-3. Under Price Cap IR, the integration of the acquired utilities in to Hydro One's rate structure would be significantly complicated by the inability to update the billing determinants underpinning current rates.

b) The acquired utilities last rebased in 2011 (Woodstock), 2012 (Norfolk) and 2014 (Haldimand). Their integration in to Hydro One's rate structure marks the first time that the cost of capital for their assets has been updated since acquisition. The update of the cost of capital parameters ensures that their costs are appropriately reflected and allocated when they are added to Hydro One's rate base in 2021.

c) See response to Exhibit I-13-CCC-15.

Energy Probe Research Foundation Interrogatory # 5

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page: 3

Interrogatory:

a) Please confirm that the methodology used to establish inflation figures was for Price Cap IR, not Revenue Cap, as Hydro One is proposing.

b) Is Hydro One aware of different inflation methodologies being used for Price Cap applications, as opposed to Revenue Cap?

Response:

a) The inflation factor used by the OEB is designed to provide an industry-specific measure of the growth in the input prices of Ontario distributors. It is calculated as the weighted average of a labour and a non-labour price index which have been determined by the OEB to be reflective of trends in the distribution sector. The derivation of this factor is not tied to a specific rate-setting mechanism in any way. Hydro One does not agree that the OEB's inflation-factor is only applicable for a Price Cap IR framework.

b) Hydro One is not aware of any instances where the derivation of the inflation factor is dependent on the form of the incentive rate-setting mechanism.

Energy Probe Research Foundation Interrogatory # 6

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-01 Page: 6
A-03-02 Page: 2

Interrogatory:

Hydro One lists a number of advantages of its proposed Revenue Cap IR model over a Price Cap IR Model.

a) Is "a Price Cap IR model" that Hydro One refers to the 4GRIM Price Cap IR model used by other electricity distributors in Ontario?

b) Is this a comprehensive list of advantages? If not what are other advantages?

c) Are there any disadvantages of the proposed Revenue Cap IR model over a Price Cap IR Model?

d) Please file all presentations, reports, memos and e-mails that were given to Hydro One senior management to obtain their approval to use the proposed Revenue Cap IR model in the EB-2017-0049 OEB application.

Response:

a) A Price Cap IR model is one where the IR mechanism is used to directly adjust distribution rates. The OEB's 4GIRM Price Cap IR model is an example of such an approach.

b) Hydro One is not aware of any other significant advantages of Revenue Cap IR over Price Cap IR. Hydro One believes that a Revenue Cap IR model more appropriately suits its overall circumstances for the reasons described in Exhibit A, Tab 3, Schedule 2 and in response to Exhibit I-7-VECC-3.

c) Hydro One is not aware of any material disadvantages over a Price Cap IR model other than the requirement of a few additional mathematical operations in order to derive rates.

d) Please see Hydro One's response to Exhibit I-3-SEC-4.

Witness: D'ANDREA Frank

OEB Staff Interrogatory # 17

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-01 Page: 8/ A-03-02 Page: 10
In-Service Capital Additions Variance Account
As part of its Custom IR proposal, Hydro One proposes the establishment of:

> *"A capital in-service variance account to track the cumulative difference over the Term between: (a) the revenue requirement associated with actual in-service capital additions during a rate year; and (b) the revenue requirement associated with the OEB-approved forecast for in-service capital additions for that year; for any capital in-service additions that are 98% or lower than the OEB-approved level; …"*

Further description of the account is provided in Exhibit A/Tab 3/Schedule 2, on page 10 where the second sub-bullet under iii) reads:

> *"Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers."*

Interrogatory:

a) Please explain exactly what is meant by this. In particular, in a hypothetical scenario where Hydro One's in-service capital additions in each year were 99% of the forecasted capital additions and on which the revenue requirement is determined and used for calculating rates in that year, Hydro One would still recover a revenue requirement higher than actual (since actual capital additions were less than forecasted), assuming that demand and the I – X-adjusted OM&A are the same as forecasted. In the scenario, why would any amount be "recoverable from ratepayers"? Since the account is proposed as being asymmetrical, under what circumstances would a balance be recoverable from customers?

b) Under bullet iii) on page 10 of Exhibit A/Tab3/Schedule 2, it is stated that the disposition of the CISVA account would be at the end of the 5-year term. Under bullet ii), it is stated that: "For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account" [Emphasis added]

The forecasted capital additions vary by each year of the Custom IR term from 2018 to 2022. For 2018, the first year of the plan, it is easy to calculate the variance. However, for successive years, how is the cumulative variance from the (approved) forecasted capital additions calculated? Using examples, please show how this account would work over the five-year Custom IR term.

Response:

a) No amount would be recoverable from rate-payers due to this account being asymmetrical. As the threshold used is 98%, an entry would only be booked if in-service additions were 98% or less of the forecasted capital additions. If in-service additions are over 98% of forecasted capital additions, no entry would be booked. It should be noted that this account is calculated annually on a cumulative basis. Therefore in a scenario where an amount is booked to the account in Year 1, and in Year 2 the cumulative in-service additions are over 100% of the cumulative forecasted amount, no entry would be booked, and the prior year's balance would remain.

b) The following table presents a theoretical example:

Dx ISAVA Calculation:						
$ in millions						
	2017*	**2018**	**2019**	**2020**	**2021**	**2022**
Dx ISA Actual	700.0	627.0	725.5	770.2	780	838.3
Dx ISA Forecast	696.0	640.9	775.6	768.1	734.3	815.1
Cumulative ISA Percentage of Forecast:		99.3%	97.2%	98.0%	99.7%	100.2%
		No Entry			No Entry	No Entry
Impact on rate base:			(34.985)	(57.806)		
Fixed Rate Debt			(0.87576)	(1.44699)		
Floating Rate Debt			(0.03205)	(0.05295)		
ROE			(1.25948)	(2.08100)		
Tax Gross Up on ROE			(0.45410)	(0.75029)		
Depreciation			(1.17991)	(1.99015)		
Total Revenue Requirement			(3.80129)	(6.32138)		
Regulatory ISA VA Account Balance:		**0.00**	**(3.80)**	**(10.12)**	**(10.12)**	**(10.12)**
* Not based on 2017 actuals. Number intended for demonstrational purposes only.						

Vulnerable Energy Consumers Coalition Interrogatory # 3

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page: 2

Interrogatory:

a) Starting at page 2 of the reference are five factors Hydro One claims make a Revenue Cap approach superior to Price Cap rate setting. For each of these factors please explain why Hydro One's proposal is a superior approach. For example, Hydro One claims Revenue Cap provides greater flexibility under which to eliminate rate classes (Seasonal). However, it is not clear why this should be the case. Please explain.

Response:

a) The proposed Revenue Cap Index is superior to Price Cap rate setting for Hydro One's overall circumstances because it allows for better flexibility and provides greater transparency when integrating the Acquired Utilities in to Hydro One's rate structure.

In keeping the rate setting mechanism at the revenue level, rather than the price level, Hydro One can more easily, and more transparently:

- add the incremental rate base and OM&A associated with the Acquired Utilities to Hydro One's revenue requirement;
- update its billing determinants and load forecast to integrate customers of the Acquired Utilities in to the proposed and existing rate classes, as applicable; and
- complete an updated cost allocation study at the time of integration to ensure fairness in the allocation of costs across all rate classes.

Price Cap IR and Revenue Cap IR are equally capable of continuing the transition to fully-fixed residential rates, eliminating the seasonal class and accommodating changes to the rate design of commercial and industrial electricity customers over the Custom IR term. Hydro One listed these additional items to provide comfort to the OEB and intervenors that the proposed Revenue Cap IR approach would not negatively impact the implementation of these key policy initiatives.

Vulnerable Energy Consumers Coalition Interrogatory # 4

Issue:
Issue 7: Is Hydro One’s proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB’s Rate Handbook?

Reference:
A-03-02

Pre-amble: Hydro One proposes to use the hybrid inflator using 70% of the GDP-IPI and 30% of the change in average weekly earnings.

Interrogatory:
a) What impact does Hydro One expect on the average weekly earnings statistics arising from the recent government policy which has and will continue to significantly increase the minimum wage.

Response:
a) Hydro One does not have the data or the expertise to speculate on the impact a change in minimum wage will have on the Average Weekly Earnings for workings in Ontario. As stated on page 2 of Exhibit A, Tab 3, Schedule 2, Hydro One is proposing to adopt the standard Inflation Factor that is determined annually by the OEB for its Revenue Cap Index.

Vulnerable Energy Consumers Coalition Interrogatory # 5

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page: 7-8

Interrogatory:

a) Please clarify what factors other than inflation are variable during the rate plan from those as shown in Table 2 (section 1.4- page 7).

Response:

a) Hydro One proposes to update its cost of capital parameters for 2021 and 2022 when it files its mid-term update in late 2020. This will result in an update to the calculation of the Capital Factor for 2021 and 2022, consistent with the methodology outlined in Table 1 of Exhibit A, Tab 3, Schedule 2. Once determined at the mid-term update, the 2021 and 2022 Capital Factors will remain unchanged for the remainder of the Custom IR period. Other than the Inflation Factor, these are the only elements of Hydro One's Revenue Cap Index shown in Table 2 of Exhibit A, Tab 3, Schedule 2 that are expected to change over the Custom IR period.

Vulnerable Energy Consumers Coalition Interrogatory # 6

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-02

Interrogatory:
a) What is the rationale for adjusting the revenue cap for cost of capital in year 4 of the program?
b) If the rationale is related to the acquired utilities please explain why a rebasing with an integrated cost allocation rate design application is not preferable in 2021.

Response:
a) Please see Hydro One's response to part (b) of Exhibit I-7-CME-1.

b) The approach proposed by VECC is inconsistent with OEB policy. As noted in Table 1 of the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, issued on October 18, 2012, an applicant filing under Custom IR has a minimum possible rate term of 5 years between rebasing applications.

Vulnerable Energy Consumers Coalition Interrogatory # 7

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-02 Page: -

Interrogatory:
a) Given the number of adjustments to rate design, OM&A and capital planning

Response:
Hydro One contacted VECC seeking clarification regarding this interrogatory. VECC informed Hydro One that it was withdrawing this question and no response was required.

Building Owners and Managers Association Toronto Interrogatory # 141

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 1

Interrogatory:

Hydro One's proposal seems to be a hybrid proposal. It describes its proposal as a Custom IR submission (A1, T2, Sch 1, pp1 and 2) but is in fact a revenue requirement approach using I-X. Have the Custom Capital component eventually made it a cost of service mechanism?

Response:

Hydro One has proposed a custom Revenue Cap Index as described in Exhibit A, Tab 3, Schedule 2. The custom capital factor provides the incremental revenue requirement associated with new capital placed in to service each year of the Custom IR term. It is not a cost of service mechanism as costs in the capital factor are reduced by a productivity factor to incent Hydro One to achieve productivity and efficiency savings in future years.

Building Owners and Managers Association Toronto Interrogatory # 142

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 1

Interrogatory:

Given that other than for 2018, Hydro One's IRM proposal is a "revenue cap IR", please explain the reference to "each test year" in line 24.

Response:

Each test year refers to the years 2019 through 2022.

Building Owners and Managers Association Toronto Interrogatory # 143

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 1

Interrogatory:

Please confirm that Hydro One's Custom Capital Factor, which is defined at p2, "to be a mechanism to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution Plan beyond the amount of revenue recovered in rates", recover revenues incremental to that deemed from rates required to fund the depreciation or return on, and taxes in respect of, capital investments that are recommended in the System Plan, and placed in-service in each year (in 2019, 2020, 2021, 2022, in which the revenue plan is in effect).

Response:

As defined on page 5 of Exhibit A, Tab 3, Schedule 2, the Custom Capital Factor is designed to ensure that the total revenue from the proposed Custom IR index is able to meet Hydro One’s specific circumstances arising from the proposed capital investments set out in Hydro One’s Distribution System Plan (Exhibit B1, Tab 1, Schedule 1).

Consumers Council of Canada Interrogatory # 12

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-01-01

Interrogatory:

In the 2017-2022 Business Plan HON has provided a Table setting out Productivity Improvements for the period 2017-2022. Please explain, in detail, how each of these numbers were derived.

Response:

Please refer to Exhibit I-25-Staff-123.

Consumers Council of Canada Interrogatory # 13

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page 4

Interrogatory:

HON is now proposing to use a stretch of .45% in its RCI formula in place of the originally proposed .6%. What is the impact on the proposed annual revenue requirement in each year arising out of this change?

Response:

The impact to revenue requirement of reducing the stretch factor to 0.45% from 0.6% is as follows:

	2019	**2020**	**2021**	**2022**
OM&A related revenue requirement	$0.9	$1.8	$2.6	$3.5
Capital related revenue requirement	$1.5	$1.5	$1.6	$1.7

Canadian Manufacturers & Exporters Interrogatory # 2

Issue:
Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:
A-03-02 Updated

Interrogatory:
a) Based on 2016 data now available from Statistics Canada, what is the projected inflation rate that will be determined by the OEB for 2018?

b) Based on the above noted inflation rate, what is the impact on the revenue requirement in 2018? Please explain fully.

Response:
a) On November 23, 2017, the OEB announced the inflation factor for rate changes effective in 2018 to be 1.2%.

b) Hydro One’s 2018 revenue requirement is unaffected by the change to the inflation rate as it is determined on cost of service basis. Changes to the inflation factor will only impact revenue requirements in subsequent years which are determined using Hydro One’s proposed Revenue Cap Index.

Canadian Manufacturers & Exporters Interrogatory # 3

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Updated

Interrogatory:

At page 4, it is stated that the productivity factor used in the rate cap index will not be updated annually, but will be maintained at the proposed stretch factor level of 0.45% for all years.

a) Will Hydro One (or PSE) be updating the analysis on an annual basis to determine if there are any changes in the custom productivity stretch factor? If not, why not?

b) How will the OEB and other interested stakeholders determine if Hydro One is improving its performance relative to the benchmark over the custom IR period in the absence of annual updates to the PSE study?

Response:

a) See Hydro One's response to Exhibit I-10-Staff-46.

b) Changes in Hydro One's performance relative to the benchmark would be re-evaluated at the time of Hydro One's next rebasing application. If interested in Hydro One's performance over the Custom IR period, stakeholders may review performance in the metrics contained in Hydro One's annual distributor scorecard as outlined in Exhibit A, Tab 5, Schedule 1. Hydro One notes that the OEB has approved a stretch factor that does not change in prior applications, such as Ontario Power Generation's ("OPG") Custom IR proceeding (EB-2016-0152). On page 129 of the decision in that proceeding, the OEB approved a stretch factor for OPG's hydroelectric business and stated that it "does not expect annual benchmarking during the IRM term."

Canadian Manufacturers & Exporters Interrogatory # 11

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-05-01

Interrogatory:

a) Has Hydro One updated Table 1 (Peer Selection Process) to reflect the proposed movement from Group V to Group IV for stretch factor purposes? If not, why not?

Response:

No. If during the application process, the OEB renders a decision that the Group IV stretch-factor should be applied, Hydro One will update the analysis referenced. It should be noted that peer selection process was based on four criteria, of which, Stretch Factor Assignments by Group was one. Therefore, it is unlikely that the peers would change.

OEB Staff Interrogatory # 18

Issue:
Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:
A-03-01 Page: 22
Table 6 provides a summary of forecasted savings due to productivity improvements over the five-year test period 2018 to 2022. Above Table 6, Hydro One states:

> *"Specifically, the Company has taken targeted actions to implement productivity improvements as early as 2018, the rebasing year, and intends to achieve further efficiencies over the subsequent four years. While the OEB's RRF provides an incentive for utilities to achieve productivity gains during the Term, such efficiencies ultimately accrue to the benefit of ratepayers at the time of the next rebasing."*

Interrogatory:
a) Please explain whether the Corporate Common productivity savings are expensed or capitalized.

b) Expenses are "current period" costs. How do productivity savings on expensed costs "ultimately accrue to the benefit of ratepayers at the time of the next rebasing" unless the lower expenses (i.e., inclusive of productivity savings) become the starting point or trend for the forecasting expenses for the test year or test period at the next rebasing?

Response:
a) Productivity savings attributed to Corporate Common costs would first be allocated to Business Units, consistent with Black & Veatch's review of allocation of common corporate costs as described in Exhibit C1, Tab 4, Schedule 1. Once allocated to Business Units, the portion to be capitalized would follow Hydro One's overhead capitalization policy as described in Black & Veatch's review of overhead capitalization rates allocation of common corporate costs in Exhibit D1, Tab 3, Schedule 1, Attachment 1.

b) Expected productivity savings have been embedded into Hydro One’s five year business plan, including the test year. The lower expenses and lower unit costs achieved during the plan period will become the starting point of the test period at the next rebasing.

OEB Staff Interrogatory # 19

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-01-01/Distribution Business Plan 2017-2022 Page: 20

At this reference in the Business Plan, Hydro One documents the following savings in pension contributions:

$M	2016	2017	2018
OM&A	16	16	16
Capital	17	17	17
Total	**33**	**33**	**33**

Above the table, Hydro One states:

> *"Hydro One's pension contribution declined for the three years, as follows, allowing reductions in OM&A by $48 million and capital by $51 million for the three years, providing a significant and immediate reduction in customer rates. These savings are in addition to the productivity savings identified in the Productivity Improvements in Business Plan above."*

Following the table, Hydro states:

> *"The capital reductions are offset by additional reinvestment, and the OM&A reductions are included in the OM&A amounts."*

Interrogatory:

a) Please explain how the pension savings provided reductions in customer rates in 2016 and 2017, and where these savings are factored into the proposed 2018 rates.

b) Please explain what OM&A reductions are factored into the 2018 proposed OM&A amounts. Is it just for the 2018 expensed pension savings?

c) Under Hydro One's Custom IR proposal, OM&A will be adjusted annually for the period 2019 through 2022 inclusive, through the proposed "inflation less productivity" factor. Does Hydro One expect that the Pension contribution savings of $16M, and subject to the I – X formula, to persist beyond 2018?

d) Hydro One will have to have actuarial revaluations done by December 31, 2018 and December 31, 2021, during the proposed Custom IR term. How does Hydro One propose to address material variations in pension contributions if they arise as a result of actuarial revaluations during the Custom IR period?

Response:

a) The pension savings (i.e. the lower contributions compared to the amounts approved by the OEB) applicable to 2016 and 2017 were recorded in the pension variance account, to be eventually refunded to customers. The 2016 balance forms part of the pension variance account balance requested for disposition as part of this application. Please refer to Exhibit I-57-Staff-272 for Pension Cost Differential Account details. The 2017 balance will be put forward for disposition in the next Distribution rate application. For 2018, the pension revaluation generated OM&A savings identified in the 2017-2022 Distribution Business Plan have been embedded in the costing of OM&A.

b) As shown on page 20 of the 2017-2022 Distribution Business Plan (see Exhibit A, Tab 3, Schedule 1, Attachment 1), 2018 OM&A was reduced by $16 million. This initial reduction relates to the Willis Towers Watson actuarial valuation as at December 31, 2015. Furthermore, Hydro One updated the filing with a blue page update in June 2017, which included another actuarial revaluation, which lowered OM&A by a further $7 million. This reduction is also described on page 6 of Exhibit Q, Tab 1, Schedule 1, filed with the OEB on December 21, 2017.

c) Hydro One is unable to confirm or deny the assumption made in this question. The next required triennial actuarial valuation of the pension plan is required as at December 31, 2019 and any variance related to pension contributions as a result of the new valuation will continue to be factored in the pension variance account.

d) Hydro One will be required to have triennial actuarial valuations of the registered pension plan as of December 31, 2019 and December 31, 2022. Any variance resulting as a result of these valuations will be factored in the pension variance account as an actual to forecast difference.

OEB Staff Interrogatory # 20

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-01-03 Page: 9 – Status Report of Auditor-General Action Items

At this reference, Hydro One documents an Advanced Metering Infrastructure for Operations and Analytics (AMIA) project, with a target date for completion of December 31, 2017.

Interrogatory:

a) Please provide a brief summary of the status of this project.

b) Have any forecasted impacts of this project been reflected in the test period from 2018 to 2022? If yes, please explain where and how these are reflected, and how Hydro One derived the impacts. If not, please provide an explanation.

Response:

a) The majority of the Advanced Metering Infrastructure for Operations project went in service in 2017.

   The Advanced Metering Infrastructure for Analytics project also went in service in 2017.

b) The impacts of these projects have been reflected in the test period. The impact is reflected in Trouble Calls. Please see Exhibit I-25-Staff-155 for details of these impacts.

OEB Staff Interrogatory # 21

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 1-2 – Revenue Cap Proposal
Hydro One describes its Custom IR proposal as:

> *"Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5- year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below."*

On page 2, Hydro one gives the formula as:

The Custom Revenue Cap Index (RCI) is expressed as:
RCI = I – X + C

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Typically, a revenue cap formula is of the form:

$$Rev_t = Rev_{t-1} \times (1 + (I - X + g))$$

where the I and X are as described above, and g (growth) is based on growth in demand (customers, consumption, energy demand). Revenues are capped by the formula, with rates set to recover the annual revenue requirement updated by this formula.

In Hydro One's proposal, the updated revenue requirement will be converted into rates each year based on the demand forecasted (where forecasted numbers of customers, kWh and kW, as applicable) are used as the billing determinants for the revenue requirement as allocated between customer classes and between fixed and variable charges.

Interrogatory:

a) Growth in operating scale is an important driver of cost growth. What is the rationale for a revenue cap index that does not include a scale escalator?

b) Please confirm that, under Hydro One's proposal, it has an opportunity, under certain conditions, of earning more revenues than the revenue requirement adjusted by the annual RCI. For example, if actual demand (as a combination of number of customers, kWh and kW) exceeds Hydro One's forecasted demand, Hydro One would receive more revenues as it would be the lower forecasted demand which would be the billing determinants for establishing rates in the year. In the alternative, please explain.

c) Why does Hydro One characterize its proposal as a revenue cap, even though it is little different than Toronto Hydro-Electric System Limited's Custom IR approved in EB-2014-0016, which was characterized there as a Price Cap?

Response:

a) Under Hydro One's RCI, any additional capital requirements required to serve any load/demand growth would be captured in the formula through the Custom Capital Factor. The expected growth in billing determinants would be captured in rates through the rate design process outlined in Exhibit H1, Tab 1, Schedule 2, wherein billing determinants are updated annually in line with the expectation of the load forecast. As a result of these two factors, Hydro One does not believe that a growth factor is required in the RCI.

b) The potential to over-recover revenue, as described by OEB staff's question, exists in all instances where rates are set based on forecast billing determinants. Likewise there is potential that Hydro One could under earn revenue if the actual number of customers, kWh and kW is lower than forecasted billing determinants. This risk is not driven by Hydro One's proposed RCI but by the fact that actual load will not exactly match the load forecast underpinning rates. A utility that was under a multi-year cost of service rate setting framework would have the same opportunity to over/under earn revenue as a utility subject to an incentive rate-setting structure such as Hydro One's proposed RCI.

c) Hydro One's proposal is appropriately characterized as a Revenue Cap Index (RCI) because the index is used to escalate the prior year's revenue requirement. Toronto Hydro's Custom IR Price Cap Index is used to directly adjust the prior year's base distribution rates.

OEB Staff Interrogatory # 22

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 4 - Stretch Factor
Hydro One states:

> *"The Productivity Factor used in the RCI will not be updated annually over the 2019 to 2022 portion of the Custom IR term. In its total cost benchmarking study, PSE conducted a forward-looking analysis using Hydro One's forecast costs for 2018-2022. This analysis concluded that Hydro One's forecast costs are likely to continue to support a 0.45% stretch factor ranking throughout the incentive rate-setting period."*

Interrogatory:

a) Under the OEB's 2nd and 3rd Generation IRM plans and the current Price Cap IR framework, a utility's ranking for assigning the stretch factor annually depends not only on its performance, but also on the performance of all other Ontario distributors, to gauge how performance in the industry as a whole is changing.

   While PSE may have had Hydro One's forecasted costs, it would not have forecasted costs for other electricity distributors in Ontario, or for other peer utilities in North America. On what basis and with what confidence have PSE and Hydro One concluded that Hydro One's performance will continue to warrant a 0.45% stretch factor throughout the period absent forecasts of how other firms costs are also expected to change in the test period?

b) Under an assumption that the annual benchmarking and assignment of a stretch factor as is currently conducted under direction of the OEB continues throughout the 5-year test period, why should Hydro One's stretch factor not be updated annually?

Response:

a) The benchmarking scores that currently warrant a 0.45% stretch factor based on the forecasted data were constructed using costs that assume full funding of Hydro One's application. PSE agrees that under the current and past IRM plans, the industry performance can impact the benchmarking scores of the studied utility. To the extent the overall industry performance changes, then the benchmarking score would be impacted. The stretch factor may be impacted due to this, however, it most likely would not be a large enough impact to change the stretch factor cohort. PSE's approach uses the historically available data as the foundation for the forecasted results. Implicit in that is an assumption that the industry performance remains unchanged compared to its historical performance. Forecasting the benchmarks using historical sample data is the best available method to provide stakeholders with accurate total cost benchmarking scores during the course of this application.

b) The benchmarking model and dataset that is currently being updated annually should not be applied to Hydro One and used as the basis of their stretch factor. Hydro One is an extreme outlier in both size and density in the Ontario-only dataset. To accurately benchmark Hydro One, the PSE dataset and variables should be used. Conducting an annual benchmarking review within a custom IR plan would create increased ongoing regulatory effort for the benefit of only one distributor, albeit a large one. This contrasts with the cited IRM situation, where the ongoing benefit is to numerous distributors within the industry. Accurately benchmarking Hydro One requires a different sample than most other Ontario distributors. It may make sense to limit this activity to once every five years rather than conduct the analysis annually. There would likely be a low chance of a different stretch factor in each year. However, PSE does believe that conducting the benchmarking research annually would provide more accurate results. This is especially true if the OEB does not fully fund Hydro One's spending request. In that case, the benchmarking results shown in part a) above should be modified to reflect those potentially lower spending levels in determining Hydro One's stretch factor.

OEB Staff Interrogatory # 23

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 - PSE Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry and Attachment 2 – PSE Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network

Interrogatory:

a) Please provide all working papers associated with the Power Systems Engineering ("PSE") studies titled "Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry" ("Productivity Report") and the updated "Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network" ("Benchmarking Report"). These working papers should include the following:
   i. All data in Excel Format.
   ii. Calculations in Excel format or program code to show the derivation of the results from publicly available data.
   iii. Identification of variable names and company ID numbers.
   iv. Any other information needed for an experienced consultant to be able to replicate the work.

   OEB staff's consultant, Pacific Economics Group ("PEG"), agrees to protect any data released by PSE in a manner consistent with agreements PSE may have with data vendors.

b) Were any of the Hydro One data used in the studies provided by Hydro One but are not provided to the OEB via the RRR? If so, please describe, and provide as part of a), identifying such data.

c) On Page 18 of Exhibit A/Tab3/Schedule 2/Attachment 1, PSE states: "PSE made one change to Hydro One's 2013 data versus what is being used in the 4th Generation IR benchmarking updates and reported in the Yearbooks, based on an inconsistent increase in the reported annual peak demand." Apart from the 2013 maximum demand adjustment, were any Hydro One data reported on the RRR corrected by Hydro One for use in the PSE study? If so, please explain.

d) Did the 2013-2015 Ontario data used for the TFP calculations include either capital or operations and maintenance (O&M) costs of smart meter installation? Please describe any adjustments made for deferred smart meter capital and/or O&M expenses.

e) Please describe how the data for Hydro One were adjusted to account for the acquisition of Norfolk. Do the Hydro One data include similar data for the Haldimand County and Woodstock acquisitions?

Response:

a) PSE has collected its working papers for the two reports. These are being submitted pursuant to the Board's *Practice Direction on Confidential Filings*, due to the commercially sensitive nature and third party data being requested.

b) All the output data (customers, kWh deliveries, and peak demand) in the study from 2005 to 2015 used RRR data except for the 2013 maximum demand adjustment, where PSE reduced Hydro One's reported demand because it was not consistent with the series and would have resulted in Hydro One's TFP (and benchmarking scores) being higher than would be accurate. Output data prior to 2005 was calculated by taking the 2005 RRR value and deflating by the percentage difference in PEG's 4GIR data for that year.

OM&A expense data, gross plant in service, and accumulated depreciation came directly from Hydro One through annual trial balance data using the Uniform System of Accounts. To avoid confusion, the trial balance data is for Hydro One's distribution activities only. This data is included in the working papers. Plant addition data was given directly to PSE by Hydro One. This data is included in the working papers.

Reliability and safety data came directly from Hydro One. This data is included in the working papers.

c) No other corrections were made to the RRR data other than the 2013 annual peak demand. During the research, PSE did discover that Hydro One's reported high voltage capital additions data that is used in the calculations for the 4GIR benchmarking updates appeared implausibly high in recent years. This created a situation where the capital additions used by PEG were extremely low. This is because PEG subtracts out the high voltage capital additions when calculating the additions used in the model. This had the effect of substantially lowering Hydro One's capital costs (and total costs) in the recent 4GIR benchmarking updates. PSE's calculated TFP trend and total cost benchmarking research includes high voltages to be consistent with the other sampled utilities and consistent with the 4GIR TFP definition. Therefore, the capital costs included in the PSE research are not impacted by the incorrect reporting of high voltage capital additions.

d) The Ontario data used for the 2013-2015 TFP calculations did not include smart meter costs from deferred capital or O&M accounts. The OM&A data was derived from PEG's 4GIR benchmarking updates, but excludes low voltage expenses and includes high voltage OM&A, to conform to the 4GIR TFP cost definition. The smart meter OM&A expenses are excluded to also conform but all appear to be zero for the years 2013-2015. This may be due to PEG not requiring a data request for the benchmarking updates and leaving this value as zero. The capital additions are derived from the reported amounts from the RRR data.

For the years 2013-2015 the OM&A and capital additions may include some on-going smart meter expenses. However, the Ontario TFP trend calculated in 4GIR already excludes a large portion of the smart meter implementation expenses. The largest expenses likely occurred prior to 2013. According to the OEB's last available Monthly Monitoring Report on Smart Meter Deployment and TOU Pricing dated on Oct. 17, 2012, "…as of August 31, 2012 99% of RPP eligible consumers have a smart meter installed…" The link to the report can be found here:

https://www.oeb.ca/oeb/_Documents/SMdeployment/Monthly_Monitoring_Report_August2012.pdf

e) Norfolk Power Distribution, Inc. was added into Hydro One to make a consistent series that is Hydro One plus Norfolk. PSE added in Norfolk's historic OM&A and capital costs (including its 2002 net plant and subsequent plant additions) into the Hydro One data. Norfolk's outputs were also added to Hydro One's outputs.

Haldimand County Hydro, Inc. and Woodstock Hydro Services, Inc. were not included in the Hydro One data.

OEB Staff Interrogatory # 24

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 - PSE Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry and Attachment 2 – PSE Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network - Personnel and Costs

Interrogatory:

PSE's Productivity Report and Benchmarking Report do not clearly state who authored the reports.

a) Please identify the principal personnel who participated in the productivity and benchmarking studies and reports, briefly summarizing their roles in the projects.

b) What were PSE's fees for these studies?

c) Please provide the terms of engagement or other instructions from Hydro One to PSE for conducting the work of these two studies.

Response:

a) Steve Fenrick was the author of the PSE Productivity and Benchmarking Reports and directed or conducted all the research and work in the studies. Other PSE employees assisted with various project tasks such as data collection and gathering efforts, review, and report writing under Mr. Fenrick's direction. Matt Sekeres was involved in many of the data collection efforts. David Williams was involved in the data work, review, and report writing tasks.

b) The fees are considered not relevant to the research contained in the studies and confidential under the OEB's Practice Direction on Confidential Filings, Appendix A, (a), i.

c) Please refer to the attachments in Exhibit I-10-SEC-010 and Exhibit I-10-SEC-020.

OEB Staff Interrogatory # 25

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 3 and 8 – Output Quantity Index

PSE states on page 3 of its Productivity Report that:

> *"The outputs used for the industry TFP trends should also be generally based on billing determinants that are related to how the distributor collects revenue. However, in determining performance, other non-revenue producing, valued outcomes should be incorporated into the evaluation. The condition to have outputs and weights that approximate distribution revenue collection would exclude the use of the adjusted TFP index as the basis for the productivity factor in incentive regulation, even if we had an industry-wide measure of it."*

PSE states on page 8 of the same report that:

> *"[t]he objective for the TFP calculated in the 4th Generation IR proceeding (EB-2010-0379) was to calculate the most appropriate productivity factor to be used in the* ***price*** *cap escalation formula."   [emphasis added]*

Interrogatory:

a) Hydro One's proposed Custom IR plan features a revenue cap index. Trends in billing determinants are widely recognized to be pertinent in the choice of an X factor for a price cap index. Please explain why they are also pertinent in the design of an X factor for a revenue cap index.

b) Ontario utilities are transitioning to rate designs with high fixed charges for Residential and possibly also for other (e.g., commercial and industrial) classes. Does this reduce the weights that are appropriate for volume and peak demand variables in the output index for productivity research intended to establish a price cap index productivity factor?

Response:

a) Billing determinant trends are not pertinent to the design of an X Factor in the context of a revenue cap index. Billing determinant trends are pertinent in the context of the design of an X Factor in the context of a price cap index. PSE extended and replicated, as closely as we could, PEG's 4GIR productivity trends in the PSE Productivity Report. It is PSE's understanding the 4GIR productivity trends calculated by PEG and used as the basis for PEG's price cap X Factor recommendation used cost elasticity weights, rather than billing determinant weights. In the context of a revenue cap, cost elasticity weights are appropriate.

PSE would also note that in a revenue cap index context, an output growth term could be considered in the escalation formula from a mathematical perspective. However, the existence of a capital factor within the escalation formula may be an adequate substitute for an output growth term.

The mathematics behind the output growth term is given below:

The allowed revenue escalation within a revenue escalation formula should mimic the expected growth in costs. Production theory postulates that there should be three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (O).

$$Growth\ Revenue = I - X + Growth\ O \qquad \text{[Equation 1]}$$

The mathematical derivation of Equation 1 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Revenue = Growth\ Cost \qquad \text{[Equation 2]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

$$Growth\ Cost = I + Growth\ \mathrm{Q} \qquad \text{[Equation 3]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (O) to Equation 3 to develop Equation 4 below.

$$Growth\ Cost = I + Growth\ Q + Growth\ O\ - Growth\ O \qquad \text{[Equation 4]}$$

The TFP trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = Growth\ O - Growth\ Q \qquad \text{[Equation 5]}$$

We can rearrange the terms in Equation 4 to the following equation.

$$Growth\ Cost = I - (Growth\ O - Growth\ Q) + Growth\ O \qquad \text{[Equation 6]}$$

And then insert Equation 5 into Equation 6.

$$Growth\ Cost = I - TFP\ trend + Growth\ O \qquad \text{[Equation 7]}$$

Therefore, if we want the growth in revenue to match the growth in cost, then Equation 7 would serve as the mathematical derivation of calculating the growth in revenue. However, in the context of a custom IR application, Hydro One is proposing a capital factor. This capital factor is anticipating the capital needs for the CIR period. It likely will then capture the growth-related capital needs for the CIR period and, at least partially, substitutes for an output factor.

b) The appropriate weights for a price cap index X Factor would reflect the billing determinant revenue weights. To the extent the billing determinant weights are changing, it would be appropriate to reflect that change in a price cap index design. It would not be appropriate in the context of a revenue cap index design to reflect a change in the billing determinant weights since the cost elasticity weights would, presumably, not be impacted due to changing billing determinant weights.

OEB Staff Interrogatory # 26

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 5 – PSE TFP study

Figure 2 shows the estimated annual TFP for the Ontario electricity distribution sector as estimated by PSE. Following the chart, PSE states:

> *"The Ontario industry had four consecutive years of TFP growth from 2002 to 2006. Then mixed results from 2007 to 2010. Since 2010, Ontario has experienced five consecutive years of TFP declines. Some of this drop is possibly due to the economic downturn. Other factors, such as aging infrastructure, increasing unmeasured outputs (e.g. environmental, regulatory, safety, customer service), and the general slowing of output growth, are also possibilities."*

While the issue of aging infrastructure is true in some instances, the Ontario electricity distribution sector has had significant capital investments in new technologies such as smart meters and associated communications technologies. Following restructuring, market opening and the legislated rate freeze, there have been major capital programs undertaken by most distributors from 2008 onwards. While there was the economic downturn in late 2008, the recovery from 2009 onwards has been positive and prolonged, even if growth is gradual. However, many distributors have seen growth in customers or connections, even if average energy consumption and demand per customer/connection is trending downwards, due, in part, to changes in the economy, technology and conservation initiatives.

Interrogatory:

As PSE has done work in the Ontario electricity sector, both for the OEB and for electricity distributors, it would have a comprehensive understanding of the Ontario electricity sector.

a) Can PSE provide a more detailed and fuller explanation for what factors are driving the negative TFP for the Ontario electricity distribution sector after 2009?

b) Could these results be also reflective of data and data adjustments that PSE made, particularly subsequent to 2012 (i.e., PEG's TFP study as done for EB-2010-0379), in conducting its analysis?

Response:

a) Please see pp.12-13 (Section 3.2) of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, for PSE's explanation of some of the possible factors that could contribute to negative TFP growth. The Productivity Report states on page 13: "Unfortunately, it is impossible to empirically adjust for all of the underlying causes of observed TFP trends. PSE addressed the safety and reliability metrics to move the TFP trends closer to being true measures of performance." This issue also arose in 4GIR and no consultant or party was able to fully explain the negative TFP growth. PSE has put forth the reliability and safety adjustments to partially explain the negative TFP growth for Hydro One. The use of the EUCPI also has the impact of creating a more negative industry TFP trend. Substituting the EUCPI for a construction cost index that does not include financing costs would likely increase measured TFP trends. This substitution would also have the off-setting impact of increasing the measured industry input price inflation and should be accompanied by an input price differential factor if implemented in the productivity factor. Please see page 25 of the Productivity Report where PSE addressed this issue.

b) If by "these results" the question is referring to the negative industry TFP trend after 2009, the first thing to say is that the PSE adjustments after 2012 had nothing to do with the substantial negative growth rates found in 2011 and 2012. After 2012, PSE only made changes to the 4GIR data where the same data or index used was not available. The EUCPI was discontinued, so we escalated the construct cost index by the Handy-Whitman index for only the year 2015. The capital addition data used the RRR data, and the OM&A used PEG's same definition for TFP in 4GIR. In PEG's benchmarking updates for 2014, 2015, and 2016 the smart meter expenses equalled zero and might not have been updated. If metering expenses had been fully excluded, this would have raised the industry TFP for 2013-2015. However, the beginning years of the sample include metering expenses, and a full exclusion of ongoing metering costs will create a biased TFP trend. According to the Ontario Energy Board's Monthly Report in October 2012, as of August 31, 2012, 99% of the smart meters for RPP eligible customers had been installed.[1]

[1] https://www.oeb.ca/oeb/_Documents/SMdeployment/Monthly_Monitoring_Report_August2012.pdf

For the years 2013-2015 the OM&A and capital additions may include smart meter expenses that are embedded in the capital additions. However, the Ontario TFP trend calculated in 4GIR already excludes a large portion of the smart meter implementation expenses. The largest additions occurred prior to 2013. Since by the end of 2012, 99% of RPP eligible customers had their smart meters installed. At some point the ongoing costs of metering customers, needs to enter into the TFP calculations, otherwise it ceases to become a "total" factor productivity study. Any operational efficiencies from smart meters are likely being captured within the TFP trends through reduced OM&A spending, thus, the ongoing metering costs should also be included. Otherwise, a bias is being created where ongoing metering costs are included in the beginning of the sample period yet excluded in the last part.

OEB Staff Interrogatory # 27

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 12-13 – Negative TFP Growth Productivity Report

PSE states that:

> *"While declining efficiency is certainly one possibility for observing negative TFP trends, there are a number of other possibilities. Given the presence of incentive regulation, it seems unlikely that efficiency is declining across the entire industry. Other systemic possibilities include:*
>
> 1. *The increasing of "outputs" that are not being measured within the TFP calculation. PSE attempts to partially solve this issue with the performance adjustments found in this study. As applied to Hydro One, we see that the long-term trend for Hydro One goes from slightly negative to slightly positive after incorporating and adjusting for the valued services of reliability and employee safety. While PSE's performance adjustments (discussed in the following section) attempt to quantify these performance outputs, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include customer service activities, meeting increased regulatory requirements, providing enhanced environmental stewardship, and increasing other aspects of power quality.*
>
> 2. *External circumstances can change over time. One of these circumstances often found in modern western economies is slower growth. Output growth has slowed due to more energy efficient appliances and machinery and conservation programs. This has slowed both the total amount of energy delivered (in kWh) and peak demands (in kW). The growth in customers, especially in more rural areas, has also slowed. Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP from historical norms.*

3. *A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during that time, utilities needed to heavily invest in capital infrastructure to meet the higher number of customers and peak demands (unlike today they were able to fund much of this investment through increasing billing determinants rather than higher prices). At a number of utilities throughout North America a high proportion of capital infrastructure is now past its useful life and is in need of replacement. However, capital expenditures may need to increase to replace this capital. Additionally, maintenance costs will also tend to increase as the grid becomes older. The capital replacement expenditures and increasing maintenance costs will tend to cause a decline in TFP."*

Interrogatory:

a) Please discuss the extent to which the following additional circumstances may have driven the productivity growth of Hydro One and other Ontario electricity distributors to be negative during this sample period:
   - Catching up on deferrable capital and OM&A expenditures following the end of the rate freeze on Ontario power distributor rates in late 2004.
   - Conversion of most Ontario power distributors during the 2012-15 period from CGAAP to alternative accounting methodologies like IFRS.

b) To the extent that these two circumstances have influenced TFP growth, is the full 2003-2015 Ontario sample a good one for establishing a productivity factor for Ontario power distributors?

Response:

a) PSE is unable to make any definitive claims as to why the negative productivity growth is occurring. A "catching up" of capital investment and OM&A expenditures due to the past rate freeze may provide one of many possible explanations.

   In the context of the TFP calculations, the transition to different accounting methodologies is only significant if the new methodologies impact reported OM&A and plant additions. TFP calculations will be unaffected if OM&A and plant additions are reported consistently across the changing accounting methodologies. There has always been a translation for utilities from their accounting procedures to reporting their balances according to the Uniform System of Accounts (USoA). To the extent the accounting transition does not change that translation of the OM&A and plant additions, the transition to IFRS (or any other accounting methodology) should not have an impact on the TFP results.

PSE did not examine the possible impacts of the accounting transition during our research for this application. If there is good evidence that the accounting switch is causing significant changes in reported OM&A and/or plant additions compared to what would have been reported with CGAAP, then the switch may have an impact. PSE does not have an opinion on the extent of this impact if it occurred.

b) PSE believes a long-run TFP trend is the most appropriate trend to use in setting X Factors for incentive regulation. The year 2002 is the first feasible start year for the Ontario dataset. PSE would be reluctant to shorten the time span from what was used by PEG in 4GIR unless there was strong and convincing evidence the change is necessary and unavoidable in providing an accurate industry TFP trend. PSE is not aware of strong evidence on the two factors mentioned in part a), so we believe the 2002-2015 Ontario sample is appropriate.

PSE also notes the impetus of our research was a directive by the Ontario Energy Board to Hydro One in the last distribution application (EB-2013-0416). The Board states in their Decision,

The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB leaves it to Hydro One to determine its preferred total factor productivity study method. **However, the period of the study should include years at least going back to 2002.** (emphasis added) The results of the study must be filed as part of Hydro One's next rates application.

OEB Staff Interrogatory # 28

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 12-13, 23 – PSE TFP study

In section 3.2, PSE provides its discussion on the interpretation of negative TFP results. Under bullet 2, it states:

> *"External circumstances can change over time. One of these circumstances often found in modern western economies is slower growth. Output growth has slowed due to more energy efficient appliances and machinery and conservation programs. This has slowed both the total amount of energy delivered (in kWh) and peak demands (in kW). The growth in customers, especially in more rural areas, has also slowed. Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP from historical norms."*

On page 23, PSE states that it used an economic depreciation rate (d_t) of 4.59% as did PEG in the EB-2010-0379 study.

OEB staff acknowledges that energy consumption and peak demand is declining, generally and for many distributors, particularly when customer growth is also considered. This does result in under-utilization of existing assets that are largely "sunk" once installed. This would result in lower productivity, all else being equal, in the short term. However, certain assets, such as transformer stations, may experience lower wear and tear and it may take longer for demand to reach designed capacity, both of which can extend the lives of such assets over time, and delaying the time for capital expenditures to replace or reinforce these assets.

As a result of an asset life study by Kinectrics Inc. commissioned by the OEB (EB-2010-0178, Asset Depreciation Study for the Ontario Energy Board, Kinectrics Inc. (Kinectrics Report) for distributors sponsored by the Board dated July 8, 2010, or of studies conducted by or on behalf of individual electricity distributors, many distribution asset lives have changed. Expected useful lives of many core distribution assets have increased. There were also changes in capitalization policies, and nearly all Ontario electricity distributors have changed from CGAAP to IFRS, US

GAAP or ASPE. Most of these changes would have occurred in 2013 or 2015, with few electricity distributors effecting changes in 2012 (i.e., at the end of the time period for PEG's analysis in EB-2010-0379).

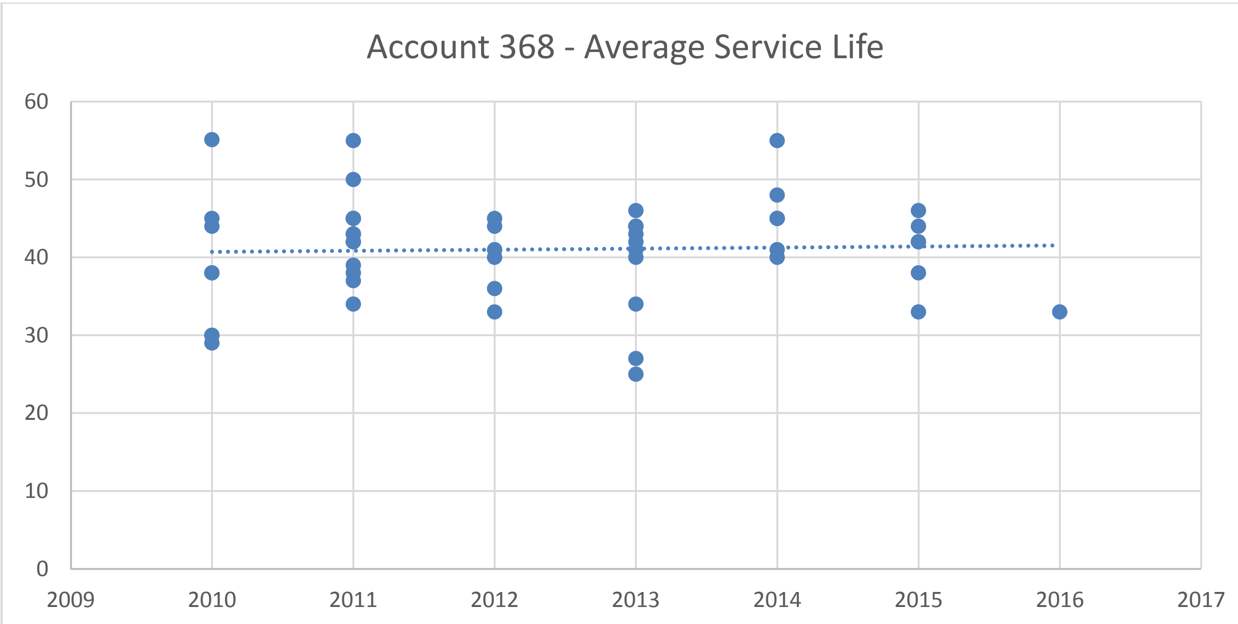
Interrogatory:

How has PSE taken into account these accounting policy changes which also, with respect to depreciation rates/expected useful lives, have real investment and operational impacts on distributors' physical networks? PSE's response should address both capital (i.e. capital stock formation and the associated index) and OM&A expenses and the associated indices.

Response:

If we consider the full array of distribution assets, it is not clear that lower demand growth would necessarily result in longer useful lives. For example, the move to electronics in recent years would tend to shorten useful lives. An example of this is electronic relays found in substation modernization. These are likely to be replaced more frequently compared to their electrical-mechanical predecessors.

The question also mentioned "transformer stations". It is unclear the exact distribution asset category that is intended to refer to. However, PSE has a depreciation rate practice and we have gathered numerous industry studies on the topic. If we look at the change from 2010 (year of the Kinetrics Study) to 2016 of 52 industry reports, there does not appear to be an obvious trend in the service lives of distribution transformers (Account 368).



PSE does not deny the premise that reduced demand may reduce equipment wear and tear. However, more evidence would be required before PSE would support an adjustment from the 4GIR assumed depreciation rates. As such, we made no adjustment to depreciation rates in the 4GIR methodology for our research.

In regards to CGAAP to IFRS, please see PSE's response to Exhibit I-8-Staff-027.

Witness: PSE

OEB Staff Interrogatory # 29

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 17 – Output Index Form

PSE states on page 17 of its Productivity Report that:

> *"For Hydro One and the industry TFP calculations, the output quantity index and input quantity index are constructed using the Törnqvist indexing method."*

Interrogatory:

Please confirm that the output quantity indexes used by PSE have fixed weights based on econometric cost elasticity estimates and therefore do not have a Törnqvist form.

Response:

Confirmed. The output quantity indexes use fixed weights.

OEB Staff Interrogatory # 30

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 22 – Geometric Decay

PSE states on page 22 of its Productivity Report that:

> *"PSE's measure of capital quantity is based on the perpetual inventory capital method. This approach has a solid basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research. [footnote omitted] The approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry."*

Interrogatory:

a) Does PSE believe that a geometric decay specification for capital cost like that which PSE has chosen to measure the productivity trend of Hydro One is the best for measuring a power distributor's cost efficiency?

b) Does PSE believe that a geometric decay specification for capital cost like that which you have chosen to measure the productivity of Ontario's power distribution industry is the best for studies intended to establish productivity factors for power distributors in IRM plans? Please explain.

Response:

a) Yes. PSE uses a monetary approach that bundles heterogeneous distribution assets into a capital stock. Decay or degradation will occur through asset failures, technological progress making assets obsolete or having reduced value, and increased maintenance and repairs as time progresses. Different types of assets will have diverse useful lives and patterns in these areas, a constant rate of decay (geometric decay) assumption is best for the heterogeneous mixture of distribution assets. This is also the same assumption used in 4GIR and a host of other productivity studies found throughout the distribution industry.

b) Same response as part a.

Witness: PSE

OEB Staff Interrogatory # 31

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 35 – Hydro One's Productivity Trend
PSE presents the trend in its "unadjusted" total factor productivity ("TFP") index for HON in Table 16. Hydro One's O&M input quantity trend is detailed in Table 6.

Interrogatory:

a) Why did Hydro One's TFP growth decline markedly in 2006 and 2007? In particular, why did Hydro One's operation, maintenance, and administration ("OM&A") input quantity growth surge following a downward trend 2003-2005?

b) Please extend your productivity calculations to include the 2017-22 period. What rate of productivity growth is implicit in Hydro One's proposed revenue requirements? This analysis should also reflect the updated evidence filed by Hydro One on December 21, 2017.

Response:

a) Hydro One's OM&A input quantity growth increased starting in 2006 because the company's OM&A expenses had relatively large increases in those years, most notably in the Administrative and General expense category.

b) PSE extended the TFP calculations to 2022 using the Hydro One capital expenditures and OM&A projections. This reflect the updated evidence filed on December 21, 2017. The TFP after 2015 is 0.0%. PSE only presents the "unadjusted" TFP since there are no projections available for safety and reliability.

Year	**TFP**
2002	**1.00**
2003	**1.00**
2004	**1.02**
2005	**1.01**
2006	**0.96**
2007	**0.89**
2008	**0.90**
2009	**0.86**
2010	**0.84**
2011	**0.84**
2012	**0.85**
2013	**0.81**
2014	**0.80**
2015	**0.83**
2016	**0.84**
2017	**0.84**
2018	**0.83**
2019	**0.83**
2020	**0.83**
2021	**0.83**
2022	**0.83**
2002-2015	**-1.4%**
2002-2010	**-2.1%**
2010-2015	**-0.4%**
2015-2022	0.0%
2017-2022	-0.1%
2018-2022	-0.2%

OEB Staff Interrogatory # 32

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 35-36 - Negative Productivity Growth

At this reference, PSE states (Productivity Report) that:

> *"… negative TFP does not necessarily imply worsening efficiency. It simply means that measured input quantity growth is outpacing measured output quantity growth. Possibilities for causes, other than worsening efficiency, include: the economic downturn, slowing output growth even absent the downturn, aging infrastructure requiring large capital replacement and increased maintenance costs, and an increase in unmeasured outputs (e.g., safety, reliability, customer service, regulatory, public safety, and environmental concerns)."*

Interrogatory:

a) What information is available on the age of Hydro One's distribution assets?

b) What evidence is there that the negative productivity growth of Hydro One has been caused by "aging infrastructure requiring large capital replacement"?

Response:

a) PSE has not reviewed Hydro One's distribution system assets or records as they relate to age. Therefore, PSE does not know what information is available on the age of Hydro One's distribution assets.

b) PSE noted "aging infrastructure requiring large capital replacement…" as one of several possibilities for a negative TFP (other than worsening efficiency). Also, as stated in a) above, PSE has not reviewed Hydro One's distribution system assets or records as they relate to age. Therefore, PSE cannot specifically point to explicit evidence that an aging infrastructure requiring large capital replacements is the cause of negative productivity growth for Hydro One. However, it is PSE's general experience that, as a whole, the age of the electric utility distribution infrastructure in North America, as well as the rate it continues to age, is an important issue that challenges the industry.

OEB Staff Interrogatory # 33

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 41 – Ontario Power Distribution Industry Productivity Trends

Interrogatory:

PSE presents information on the TFP growth of Ontario's power distribution industry in Table 20.

a) Please expand this table (or prepare additional tables) to present analogous annual results on the following related variables:
   - Output quantity subindexes (e.g. kWh delivered, maximum peak demand, and the number of customers served)
   - Input quantity subindexes [e.g. capital, labor, materials, and OM&A inputs].
   - Partial factor productivity ("PFP") of capital inputs
   - PFP of O&M inputs

b) Please add annual growth rates to the expanded table(s).

c) What do these expanded results tell us about the drivers of the purported negative industry productivity growth?

d) Please make sure that the working papers include productivity calculations for each Ontario LDC used in the study and prepare a table that reports trends for each distributor for the ten-year period 2002-2012 and the additional three years 2013-2015 (i.e. three growth rates).

Response:

a) See below for the requested tables. PSE could not provide a breakdown of the labour and materials for the input quantity subindexes, since only OM&A data is reported. We do not have a breakdown of OM&A by its labour and non-labour components for the Ontario industry.

Table 20 with Annual Growth Rates						
Year	Output Quantity		Input Quantity		TFP	
2002	100.0		100.0		100.0	
2003	102.1	2.1%	101.3	1.3%	100.8	0.8%
2004	104.0	1.8%	101.8	0.5%	102.1	1.3%
2005	106.8	2.7%	102.4	0.6%	104.3	2.1%
2006	108.2	1.3%	103.5	1.1%	104.5	0.2%
2007	109.7	1.4%	106.6	3.0%	102.9	-1.6%
2008	110.6	0.8%	108.1	1.4%	102.3	-0.6%
2009	110.8	0.2%	108.4	0.3%	102.2	-0.1%
2010	111.8	0.9%	108.6	0.2%	103.0	0.7%
2011	112.8	0.9%	110.9	2.1%	101.7	-1.2%
2012	114.0	1.0%	116.7	5.1%	97.7	-4.1%
2013	114.8	0.8%	123.0	5.3%	93.3	-4.5%
2014	115.6	0.7%	126.5	2.8%	91.4	-2.1%
2015	115.6	0.0%	130.2	2.9%	88.8	-2.9%
2002-2015	1.1%		2.0%		-0.9%	
2002-2010	1.4%		1.0%		0.4%	
2010-2015	0.7%		3.6%		-3.0%	

Output Quantity Subindexes						
Year	Total Customers		kWh delivered		Maximum Peak Demand	
2002	2,528,664		65,523,878,635		14,953,754	
2003	2,590,817	2.4%	67,480,321,397	2.9%	15,124,270	1.1%
2004	2,647,118	2.1%	68,588,997,365	1.6%	15,282,376	1.0%
2005	2,703,821	2.1%	72,989,180,570	6.2%	15,710,004	2.8%
2006	2,748,114	1.6%	71,323,881,577	-2.3%	16,004,095	1.9%
2007	2,781,589	1.2%	75,581,326,413	5.8%	16,030,411	0.2%
2008	2,823,654	1.5%	74,626,460,193	-1.3%	16,038,942	0.1%
2009	2,849,054	0.9%	71,454,871,353	-4.3%	16,094,053	0.3%
2010	2,885,251	1.3%	71,603,206,532	0.2%	16,170,104	0.5%
2011	2,919,186	1.2%	71,223,956,582	-0.5%	16,285,594	0.7%
2012	2,954,040	1.2%	72,183,916,383	1.3%	16,389,619	0.6%
2013	2,990,793	1.2%	71,727,216,415	-0.6%	16,433,473	0.3%
2014	3,025,345	1.1%	71,538,196,654	-0.3%	16,433,656	0.0%
2015	3,039,432	0.5%	70,911,432,897	-0.9%	16,341,494	-0.6%
2002-2015	1.4%		0.6%		0.7%	
2002-2010	1.6%		1.1%		1.0%	
2010-2015	1.0%		-0.2%		0.2%	

Input Quantity Subindexes

Year	Capital		OM&A	
2002	46,009,650		4,473,539	
2003	46,477,755	1.0%	4,553,483	1.8%
2004	47,256,994	1.7%	4,485,136	-1.5%
2005	48,041,320	1.6%	4,434,265	-1.1%
2006	48,428,136	0.8%	4,501,383	1.5%
2007	49,622,372	2.4%	4,676,665	3.8%
2008	50,200,297	1.2%	4,759,910	1.8%
2009	50,297,396	0.2%	4,776,711	0.4%
2010	51,209,677	1.8%	4,661,127	-2.4%
2011	51,878,890	1.3%	4,820,951	3.4%
2012	53,003,588	2.1%	5,303,981	9.5%
2013	55,332,102	4.3%	5,665,820	6.6%
2014	57,594,410	4.0%	5,733,180	1.2%
2015	60,287,750	4.6%	5,765,326	0.6%
2002-2015	2.1%		2.0%	
2002-2010	1.3%		0.5%	
2010-2015	3.3%		4.3%	

Partial Factor Productivity

Year	Capital		OM&A	
2002	100.0		100.0	
2003	101.1	1.1%	100.3	0.3%
2004	101.2	0.1%	103.7	3.3%
2005	102.3	1.1%	107.8	3.9%
2006	102.8	0.5%	107.5	-0.2%
2007	101.7	-1.0%	105.0	-2.4%
2008	101.4	-0.4%	104.0	-1.0%
2009	101.4	0.0%	103.8	-0.2%
2010	100.5	-0.9%	107.3	3.4%
2011	100.0	-0.4%	104.7	-2.5%
2012	98.9	-1.1%	96.1	-8.5%
2013	95.5	-3.5%	90.7	-5.8%
2014	92.4	-3.3%	90.2	-0.5%
2015	88.3	-4.5%	89.7	-0.5%
2002-2015	-1.0%		-0.8%	
2002-2010	0.1%		0.9%	
2010-2015	-2.6%		-3.6%	

b) See tables in part a). The annual growth rates have been added to each table.

c) The slowdown in industry TFP has resulted from both capital and OM&A PFPs being negative. Capital PFP has declined by approximately 1.0% from 2002-2015, and OM&A PFP has declined by 0.8%. In the more recent years, both capital and OM&A PFP have experienced large declines. Capital PFP has declined by 2.6% since 2010, and OM&A PFP has declined by 3.6%.

d) Please see working papers in the file "Ontario Update to 2015 of 4GIR TFP.xls".

OEB Staff Interrogatory # 34

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-02 Page: 11 - Inflation Forecasts

PSE states:

> *"For the years 2017-2022, projected values were used for Hydro One's variables."*

Interrogatory:

Input prices are calculated using the same procedures as the historical data but with inflation projections. Input prices are divided into two categories: capital and OM&A. There are two components used to construct the OM&A input price: labour and non-labour. The non-labour component is set to increase by 1.57% per year. The labour component is set to increase by 2.56% per year. These are the default values used in the OEB total cost benchmarking model projections worksheet. The capital category is set to increase at the same rate as the labour component at 2.56% per year.

a) Was the construction cost index or the capital price escalated by 2.56%? If the former, what assumption was made about the rate of return on capital?

b) In either event, what is the rationale for using 2.56% as the escalator? Is this consistent with PEG's benchmarking work for the OEB?

Response:

a) The construction cost index was escalated by 2.56%. The rate of return on capital assumption for the projected years used the 2015 value of 6.51% for the cost of capital.

b) The historic growth in the North Atlantic Handy-Whitman index that measures the construction costs of the electric distribution industry grew at a rapid pace of 5.4% from 2002 – 2015. This pace slowed to 3.5% from 2010 – 2015. The Handy-Whitman index is the measure we used in calculating the historic construction costs. From this standpoint, PSE's assumed growth of 2.56% is on the low end of an appropriate range.

Furthermore, PSE noted PEG's recent research, where PEG used a 2.58% assumption in escalating construction costs in their work for Oshawa PUC.[1] This growth rate used by PEG was based on the Conference Board of Canada price projections for "Engineering Structures, Electric power generation, transmission, and distribution".

PSE also interpreted PEG's use of the term "default" values in the projections worksheet as meaning this may not be the exact assumed values that PEG would ultimately use. This was just a default value inserted in the projections worksheet to help distributors. PSE felt that in the present case, PEG would, instead, escalate the construction costs by a more appropriate and higher growth rate (similar to the assumption they made in their Oshawa PUC research). In that case PEG used a 2.58% growth rate. PSE used a 2.56% growth rate in our research.

[1] PEG Report, "Benchmarking the Forecasted Cost of Oshawa PUC Networks", December 18, 2014. EB-2014-0101, Exhibit 10, Tab A.

OEB Staff Interrogatory # 35

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-02 Page: 17 - Model Estimation Procedure

PSE states on p. 17 that:

> *"The model is estimated using generalized least squares (GLS) in order to correct for cross-sectional heteroskedasticity. The parameter estimates that result from this procedure are both consistent and efficient."*

Interrogatory:

a) Why did the estimation procedure not correct for autocorrelation as well as heteroskedasticity?

b) Were Hydro One data used to estimate the model used to benchmark Hydro One?

Response:

a) Correcting for autocorrelation in unbalanced panel datasets is not a straightforward process. The differences in the two results (with and without an autocorrelation correction) are also quite small in this case. As we discuss below, autocorrelation does not cause the model to be biased. Given the following factors, PSE thought it best and most transparent to avoid unnecessarily complicating the modeling procedures:
   - The small impacts of correcting for autocorrelation,
   - The complicated and technical methods of performing such a correction,
   - The existence of unbiased and widely accepted sources of parameter estimates, and
   - Academic disputes in the literature regarding unbalanced panel autocorrelation corrections (i.e., a lack of a widely accepted consensus).

   However, we provide a full explanation of the issue and provide autocorrelated-corrected results below in response to this question.

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to "explain" movement in the dependent (often called the left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues causes the coefficient values to be biased. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the statements about precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weight the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation have focused the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies have been to leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis in response to this interrogatory, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[1] The Driscoll-Kraay standard errors are calculated by putting less weight on the relationship between error terms that are "far

[1] Driscoll, J., and A. C. Kraay. 1998. "*Consistent covariance matrix estimation with spatially dependent data*". Review of Economics and Statistics 80: 549–560.

away" from each other. By far away, we mean they might be from different utilities, or from the early versus the latter part of the time period studied. Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[2] We estimated the model using STATA version 15. The computer software calculates information crucial to understanding whether each relationship as described by each coefficient can be supported statistically. These statistical claims are usually reported as either t-ratios or probability values.[3]

We will present both, but our discussion will use the probability values, or more commonly called *p-values*. For a regression coefficient to be called statistically significant, its associated p-value must be less than a pre-set significance level. A common threshold is a p-value of 0.10. What this means is that if the reported p-value on a coefficient is below the significance level of 0.10, then there is more than a 90% level of confidence that the associated factor is explaining the dependent variable. All first order terms remain statistically significant at this 90% level of confidence. This statement about statistical significance is actually a statement about a presumed hypothesis test. Technically speaking, hypothesis tests are conducted in a *counter-factual* manner.[4] The null (or maintained) hypothesis is that there is *not* a statistical relationship. If the variable is shown to be insignificant, it means that there is a *failure to reject* the null hypothesis in that case. If the variable is statistically significant, it means that the null hypothesis (no statistical relationship) is *rejected* because the researcher now has statistical support that the variable in question does indeed explain the dependent variable.

The model using the exact same dataset, but using the Driscoll-Kraay procedure, is presented in the table below. Each coefficient value is shown in the second column. The third column presents the t-statistics. P-values are presented in the 4th column.

[2] Hoechle, Daniel. 2007 "Robust standard errors for panel regressions with cross-sectional dependence". The Stata Journal 7(3):281-312.
[3] See Wooldridge, J. *Introductory Econometrics*, *4th Edition*, pgs 122.
[4] See Wooldridge, p. 133-135 for a discussion of hypothesis testing.

Total Cost Model Estimates

VARIABLE KEY

N=	Number retail customers
D=	Maximum peak demand
A=	Square kilometers of territory per customer
E=	Percent electric customers
F=	Percent forestation in service territory
CSI=	Percent customer service and information expenses
W=	Extreme weather
Art=	Percent of territory that is artificial surfaces

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-Statistic	P-Value		EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-Statistic	P-Value
N	0.816	183.840	0.000		CSI	0.008	3.910	0.000
NN	0.149	3.260	0.001					
ND	-0.179	-2.000	0.046		W	0.00001	4.98000	0.00000
D	0.095	19.590	0.000		Art	1.894	14.730	0.000
DD	0.045	1.010	0.312					
					Trend	-0.002	-1.930	0.054
A	0.066	12.860	0.000					
					Constant	12.047	501.000	0.000
E	0.095	8.230	0.000					
F	0.051	8.850	0.000					

The benchmarking results for Hydro One using the Driscoll-Kraay procedure are provided in the table below. We put side-by-side the original results along with the Driscoll-Kraay results in a modified version of Table 3-3 in the PSE Benchmarking Report. A slight change in results occurs, but Hydro One remains within the 0.45% stretch factor threshold.

Table 0-1 Hydro One's Cost Performance 2017-2022

Year	% Difference from Benchmark Total Cost (PSE Report)	% Difference from Benchmark Total Cost (Driscoll-Kraay)
2017	+21.3%	+22.5%
2018	+21.4%	+22.8%
2019	+22.0%	+23.5%
2020	+22.4%	+24.0%
2021	+22.4%	+24.1%
2022	+22.7%	+24.5%
Average 2017-2022	**+22.0%**	**+23.6%**

b) No. The model used to benchmark Hydro One excludes the company's observations from the model, making it an external industry benchmark.

OEB Staff Interrogatory # 36

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-05-01 Page: 50-51 - Regulatory Return on Equity

Interrogatory:

What is Hydro One Distribution's achieved Return on Equity on a regulated basis for 2016? Please provide a synopsis for the factors influencing this result.

Response:

Hydro One Distribution's achieved Return on Equity on a regulated basis for 2016 was 8.41 per cent.

Regulated net income as reported in the annual RRR filing for 2016, section E2.1.7 Trial Balance was $270.5M.

Adjusted regulated net income before tax adjustments decreased by 39.1M in 2016 relative to RRR value, primarily due to the following:

- +$3.4M non-rate regulated items and other adjustments
- +$2.3M non-recoverable donations
- -$1.2M net interest/carrying charges from Deferral and Variance Accounts
- -$43.6M interest adjustments for deemed debt

Adjusted regulated net income after tax adjustments was $240.2M, primarily due to the following regulatory adjustments:

- +$36.2M future/deferred tax expense
- +$22.3M current income tax expense
- -$49.6M current income tax expense for regulated ROE purposes

Regulated common equity as reported in the annual RRR filing for 2016, section E2.1.5.6 Regulated Return on Equity, ROE Summary was $2,855.3M, resulting in a Return on Equity of 8.41 per cent.

OEB Staff Interrogatory # 37

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

B1-01-01 Section 1.5/Table 17, 18 and 19
Productivity Savings – Operations

Table 18 shows the savings forecasted by Hydro One for Cable Locates, and Table 19 shows the savings forecasted for Vegetation Management. These are programs under Operations, for which the forecasted savings are shown in Table 17. OEB staff has prepared the following table from the data in Tables 17, 18, and 19:

Forecasted Operations Savings by Program
Exhibit B1-1-1/DSP Section 1.5/Tables 17, 18, 19

$M

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Cable Locates (Table 18)	7.8	7.6	7.9	8.1	8.2	39.6
Forestry (Table 19)	10	12.9	13.8	14.9	17.4	69
Sub-total	17.8	20.5	21.7	23	25.6	108.6
Total Operations (Table 17)	20	23.1	24.1	25.4	28	120.6
Difference = "Other" Operations Savings	2.2	2.6	2.4	2.4	2.4	12

Interrogatory:

Savings from Operations programs and projects other than Cable Locates and Forestry (Vegetation Management) average about $2.4M per year.

a) Please describe briefly what other operational savings would make up this $2.4M per year.

b) In light of the updated evidence filed by Hydro One on December 21, 2017, please update this table if necessary, or confirm that no update is required.

Response:

a) The table prepared by OEB Staff has been corrected to reflect the evidence filed for Table 18 – Cable Locates Savings Forecast, for the years 2018 and 2019 (highlighted).

Forecasted Operations Savings by Program
Exhibit B1-1-1/DSP Section 1.5/Tables 17, 18, 19
$M

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Cable Locates (Table 18)	7.6	7.8	7.9	8.1	8.2	32.0
Forestry (Table 19)	10	12.9	13.8	14.9	17.4	69
Sub-total	17.6	20.7	21.7	23	25.6	108.6
Total Operations (Table 17)	20	23.1	24.1	25.4	28	120.6
Difference = “Other” Operations Savings	2.4	2.4	2.4	2.4	2.4	12.0

The updated evidence filed on December 21, 2017 includes updated savings for Operations. The “Other” Operations Savings (excluding Forestry and Cable Locates) has increased to an average of $3.9 million annually.

The “Other” Operations Savings are primarily made up of:

- Fault Indicator Deployment - Fault indicators are devices which indicate the passage of fault current. When properly applied, they can reduce operating costs and reduce service interruptions by identifying the section of cable that has failed.

- Work Team Migration in Engineering – A reduction in support staff that was utilizing the legacy software

- Stations Services Initiatives including overtime reductions, utilization of temporary work headquarters and efficiencies from implementation of a new scheduling tool

- Flexible Bill Window resulting in a reduction in manual meter reads

b) The OEB Staff table has been updated below:

Forecasted Operations Savings by Program
$M

Year	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Cable Locates	7.6	7.8	7.9	8.1	8.2	32.0
Forestry *	2.8	4.1	5.9	6.9	7.9	27.5
Sub-total	10.4	11.9	13.8	15.0	16.1	67.1
Total Operations	14.3	15.8	17.7	18.9	20.0	86.8
Difference = “Other” Operations Savings	3.9	4.0	4.0	4.0	4.0	19.7

*The previous Forestry productivity plan was based on Hydro One’s forestry strategy prior to moving to the new vegetation management strategy. As a result of the change in execution strategy (at no increase in cost), some legacy initiatives are no longer possible to implement and monitor and have been removed from the savings plan. Hydro One has increased the allocation in other areas (procurement and fleet telematics).

OEB Staff Interrogatory # 38

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

B1-01-01 Section 1.5/Section 1.5.1.3/Table 20
Productivity Savings – Procurement

In section 1.5.1.3, Hydro One describes the forecasted savings by year with respect to the Procurement program. Table 20 provides a detailed breakdown of forecasted savings. Hydro One states on page 9 of this exhibit:

> *"Table 20 lists spending categories and the forecast procurement savings that have been embedded in the business plan over the 2018-2022 planning period."*

Interrogatory:

How have these savings been reflected in the revenue requirement, given Hydro One's proposed custom IR proposal? In other words, how are the benefits of these savings shared with Hydro One's ratepayers?

Response:

Please see response to Exhibit I-10-Staff-47.

Vulnerable Energy Consumers Coalition Interrogatory # 8

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01
Exhibit A, Tab 3, Schedule 1 7 Exhibit A-3-2, Attachment 1 (PSE TFP Study)

Interrogatory:

a) In its TFP Report dated November 4, 2016 “PSE recommends setting the stretch factor no higher than 0.6%” (page 5). Is the only difference between this recommendation and that made in the May 18, 2017 Report the addition analysis drawn from adding data from U.S. utilities? If not please list all other factors which caused PSE to change its November 16, 2016 recommendation.

b) Please list the methodological differences as between the PSE Benchmarking Study and the PEG July 2017 Benchmark Study provided to the Ontario Energy Board.

c) Does Hydro dispute any of the conclusions in the 2017 PEG Study?

d) Please comment on the sensitivity of the model to adding or subtracting years of data. Specifically, what sensitivity analysis was undertaken to PSE to understand the stability of the model?

Response:

a) The difference was that when the TFP Report came out in November, 4, 2016, PSE had not yet conducted the total cost benchmarking research for Hydro One. On that same page 5 of the TFP report PSE states: “PSE is of the opinion that accurate total cost benchmarking is the best approach to setting stretch factors.” Once PSE conducted the total cost benchmarking subsequent to that report, the stretch factor was based on the total cost benchmarking results.

b) There are not any major methodological differences, in PSE’s opinion. Three of the most prominent differences in key items within the basic methodological framework are: (1) the different datasets used, (2) the included variables to explain total cost values, and (3) the cost definitions are slightly different to assure consistency with the different datasets.

Witness: PSE

c) The dataset used in the 2017 PEG Study does not allow for an accurate benchmarking study of Hydro One. The dataset used in the 2017 PEG Study is an Ontario-only dataset. Hydro One's service territory covers around 75% of Ontario, and when the utility to be studied comprises such a large portion of the dataset to be benchmarked, the results are not accurate.

d) Hydro One's large size relative to other Ontario utilities means that it is an extreme outlier within the Ontario-only sample. This is true both in terms of size and customer density. Explanatory variables estimated within an econometric model are most accurate at the mean (or average) of the dataset. They then become less accurate as observations move away from that mean value. Furthermore, there are no observations that "encompass" Hydro One in the Ontario dataset—in other words, there are no distributors larger than Hydro One and no distributors with the rural characteristics. Thus, when an Ontario-only dataset is used, it significantly reduces the total cost model's accuracy, since the parameter estimates have no observations close to the variable values of Hydro One.

e) The benchmarking results for Hydro One will change if years are excluded from the sample period. PSE used 2002 as the start year because this is the first feasible start year for Hydro One. PSE did not test out other start years in our research. In response to this interrogatory, PSE tested the sensitivity by excluding the first three years of the sample period from the dataset. This produced a dataset from 2005 to 2015. Hydro One's benchmark result in 2016 changed from +21.6% to +16.2%. Both of these results are within the stretch factor threshold, indicating a 0.45% stretch factor.

Vulnerable Energy Consumers Coalition Interrogatory # 9

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-01 Page: 22

Interrogatory:

a) Please provide a list of productivity initiatives for each of the years 2018 through to 2022 which underpin the savings forecast.

Response:

a) Please refer to Exhibit I-25-Staff-123 for a description of the initiatives and underlying assumptions.

Witness: LOPEZ Chris

Building Owners and Managers Association Toronto Interrogatory # 1

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 14

Interrogatory:

a) Please confirm that this study does not include econometric total cost benefit research notwithstanding the fact that the Board expressed a preference for econometric total cost benchmarking.

b) The Board requested HONI measure its total factor productivity over time, so as to be able to demonstrate constantly improving productivity to its customers and the OEB. Why has Power Engineering produced a study which introduces other aspects of HONI's performance, reliability and safety? Please provide a copy of the RFP.

c) Does Power Engineering equate utility productivity as measured by a TFP study, which uses the outputs of kwh, kw and customer numbers, with utility performance, often measured by a utility scorecard, which contains indices of performance that are valued by customers such as reliability, customer service, and the like. Please explain fully.

d) Please confirm that benefits to employees, as opposed to increased value for customers, are not considered part of a customer scorecard, or a TFP study, or trend study.

e) Please indicate the Hydro One safety record in each year of the study period.

f) Has the definition of recorded industry changed over the period?

Response:

a) A separate Total Cost Benchmarking study has been completed by PSE and was filed in the application as Exhibit A, Tab 3, Schedule 2, Attachment 2, Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022).

b) Please refer to p.7 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario where PSE states, ‘The purpose of calculating an adjusted TFP for Hydro One, in addition to the unadjusted TFP, is to make the performance trends more comprehensive. Connecting customers to the distribution grid and investing in the system capacity to deliver energy at peak demands is a highly valued service to customers. However, enhancing the reliability of the grid and assuring a safe work environment are also highly valued outcomes of distribution utilities. In evaluating distributor performance it is important to incorporate these important activities.

For copies of the relevant contract documents, please refer to Exhibit I-10-SEC-020.

c) A TFP trend study that uses the stated outputs would cover an important aspect of how the utility performance is changing over time. However, such a study would not provide the full performance picture. A TFP measure with the outputs as stated in the question would leave out several important performance aspects.

d) The question would need to cite the specific scorecard, TFP study, or trend study being asked about for PSE to answer. The TFP study produced by PSE did include employee safety as one component of the study.

e) Please see Table 9 on p. 29 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry.

f) The question is not clear. If “industry” means “injury” then please refer to Exhibit I-9-BOMA-002.

Building Owners and Managers Association Toronto Interrogatory # 2

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 1

Interrogatory:
a) Is definition of injury constant?

b) How are major event days defined? How many major event days were there in each year of the study?

Response:
a) Yes.

b) Please refer to p. 31 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario. PSE states:

The extreme weather definition used is consistent throughout the study period, and is based on Hydro One's definition of a major event. The definition of a major event day is any day when 10% or more of Hydro One's customers have been interrupted by an event.

Full Year	**2012**	**1013**	**2014**	**2015**	**2016**
Number of FM Days	13	33	4	11	9

Building Owners and Managers Association Toronto Interrogatory # 3

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 1

Interrogatory:
a) The Board has also expressed utilities intent in being benchmarked against their peers. Why has HONI not done this for this case?

b) Does the exclusion of major event days not leave out resilience of the measured systems? Please discuss

Response:
a) PSE has conducted econometric total cost benchmarking research that benchmarks Hydro One to their U.S. industry peers. Please refer to Exhibit A, Tab 3, Schedule 2, Attachment 2 Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022).

b) PSE is unsure what definition of "resilience" is being used. Excluding major event days does not incorporate the impacts of outages during those extreme days, so to that extent, a definition of "resilience" that includes outage times on major event days is not addressed by PSE's study. However, the "resilience" of the system during outages is contained in the study for those days where there are outages, but where the day does not trigger the major event day definition (again, depending what exactly is meant by "resilience").

Building Owners and Managers Association Toronto Interrogatory # 4

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 5

Interrogatory:
a) While employee safety is important, it is not normally included in productivity studies, including TFP studies. What other aspects of utility performance, eg. customer service related performance, greenness, are not included?

b) Please confirm that the year 2002 was assigned a Total Factor Productivity ("TFP") of 1.0 (both unadjusted and adjusted) as indicative of its base year status for the study. The declines or increases shown on Table 1 are with reference to the previous year.

c) What has accounted for the volatility of TFP trend, both unadjusted and adjusted?

Response:
a) Other aspects of performance could include customer service, meeting increased regulatory requirements, providing enhanced environmental stewardship, and increasing other aspects of power quality. Please see pp. 12-13 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry for a fuller explanation.

b) Confirmed that 2002 was assigned a value of 1.0. The Table 1 TFP index references in the PSE Productivity Report are relative to that 2002 value of 1.0. The percentages reported on the bottom of Table 1 are average annual growth rates of the TFP indexes based on the time period displayed.

c) The volatility of the TFP trends are a function of the change in the output quantity index and input quantity index. The output quantity index for Hydro One has grown at a slow but steady pace. Most of the volatility in the TFP trends is a product of the volatility in the input quantity index.

Building Owners and Managers Association Toronto Interrogatory # 5

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 9

Interrogatory:

Have the safety and the reliability factors been included in determining the adjusted TFP?

Response:

Yes. Please refer to pp. 28-34 in Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry for a full explanation.

Building Owners and Managers Association Toronto Interrogatory # 6

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 8

Interrogatory:

Since 2010, the Ontario electricity industry has experienced five consecutive years of TFP declines. Did Power Engineering do any detailed analyses of the reasons for these deadlines? Was it part of your task?

Response:

PSE provides some possible explanations for the declines on pp. 12-13 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry. PSE did not conduct any detailed analysis for the reasons of the declines, nor was it part of our work scope.

Building Owners and Managers Association Toronto Interrogatory # 7

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 9 Importance of the Output Factors

Interrogatory:

a) What do you mean by extended benefits? Please list all of the extended benefits that may affect the utility's performance.

b) Are there other electricity TFP studies of different companies that you have done, or are aware of, where the analysts have set the industry TFP at zero percent, or at a negative number?

Response:

a) PSE does not see the term "extended benefits" on the referenced page. There is a reference to "externalized benefits." If that is what the question is referring to, then externalized benefits means activities conducted by the distributor that accrue benefits to parties external to the company. An example of externalized benefits are reliability, customer service, safety, power quality, environmental stewardship, and other activities that benefit parties outside of the company.

b) In response to this question PSE did not undertake an exhaustive search but the most salient TFP study is the one conducted by PEG in 4GIR. In the study, the Ontario industry was found by PEG to have a negative TFP growth rate: -0.33%. This growth rate was calculated after excluding Hydro One and Toronto Hydro, due to their negative TFP growth rates at the time.

Other studies have shown negative TFP trends within the electric distribution industry as well. A recent study conducted by Pacific Economics Group (PEG) in New Zealand estimated that industry's electric distribution industry's TFP at -1.34%. Please see PEG's report dated June 2014, titled *Productivity Trends of New Zealand Electricity Distributors*. A report from the Grid Modernization Laboratory Consortium recently reported negative

TFP for California distributors.[1] In the recent Ontario Power Generation proceeding (EB-2016-0152), London Economics, Inc. reported negative productivity growth for North American hydroelectric generation.

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[1] Lowry, MN, M Makos, J Deason, and L Schwartz; *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*.

Building Owners and Managers Association Toronto Interrogatory # 8

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 11

Interrogatory:

a) Why, in your understanding, did PSE not support the exclusion of Hydro One and Toronto Hydro from the study for EB-2010-0379?

b) Why was the Electric Utility Construction Price Index ("EUCPI") suspended as an index in 2015?

c) Please provide a copy of the Handy Utilities index for electric distribution for 2014-2015. What states and large cities does the index include? What other regional cost indices are there? Please provide a list of them.

d) Are the reliability weights shown at Table 15, the percentage weights they are allotted in the calculation of the adjusted TPF?

e) Please show the calculation that alters column 2 to column 3, with the addition of the increase in safety.

f) Please do the similar calculation for Table 18.

g) Please provide the similar calculation for Table 19.

Response:

a) PSE did not support the exclusion of Hydro One and Toronto Hydro from calculation of the industry productivity factor for the simple reason that Hydro One and Toronto Hydro are large parts of the industry. If the consultant is allowed to pick and choose the distributors that comprise the industry, then the study ceases to be objective and becomes more subjective. The reported TFP trend of -0.33% did not reflect the whole industry in Ontario, but rather a subset that was selected by the researcher. This opens the door to the researcher selecting the sample that best fits the answer they desire. PSE believes the productivity factor should be based on the whole distribution industry TFP trend, without the subjective decisions of which distributors to eliminate from the industry sample.

b) On p.25 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, PSE inserted the Statistics Canada "Notice of program review". In that they state: "The program will be reviewed to ensure the models used in the future take into account current practices in construction."

c) The Handy-Whitman indexes are provided based on a paid subscription. The data we used for the study is available in the working papers subject to a signed Confidentiality Agreement. Please see the response to interrogatory Exhibit I-8-Staff-023. The Handy-Whitman construction cost indexes include six U.S. regions for the indexes. Beyond the total distribution construction cost index, they provide a host of other utility construction cost indexes, including specific distribution plant categories. Here is a link to the Handy-Whitman product for more information: https://wrallp.com/about-us/handy-whitman-index

d) Yes.

e) All calculations are provided in PSE's working papers. Please see response to interrogatory Exhibit I-8-Staff-023. The basic idea is that using the stated reliability weights in Table 15, the 3-year rolling average annual trend in the reliability metrics is subtracted from the trend in the unadjusted TFP to come up with the adjusted trend of the index. The reason the reliability trend is subtracted is because lower SAIFI and CAIDI values indicate better performance.

f) Please see the response to part e.

g) Please see the response to part e.

Building Owners and Managers Association Toronto Interrogatory # 9

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 12

Interrogatory:

Preamble: "Negative TFP trends do indicate that measured outputs are growing slower than inputs".

a) Has growth in customers, kwh, or kw slowed over the period 2002-2015? Please provide the data for each year from 2002 to 2015, inclusive.

b) Please provide data on the age of Ontario's utility capital infrastructure over the period 2002 to 2015.

c) Is the age of Hydro One Distribution assets representative of Ontario industry's age of assets? To what extent? Please provide whatever data is available.

d) How compliant with increased regulatory standards or enhanced environmental standards are considered an adjustment to a productivity study or trend? Are they not part of the legal framework in which the utility operates?

e) What would OM&A impact be if average of non-management labour index the costs of non-management employees?

Response:

a) Please see PSE's response to Exhibit I-8-Staff-23, part a). This data is available in the working papers, which is subject to a confidentiality agreement. Yes, the growth in outputs for the Ontario industry has slowed.

b) PSE is not aware of the existence of this data.

c) PSE is not aware of any data or analysis that would enable a response to these questions.

d) These were not factors included in PSE's Productivity study, due to the fact that no accepted metric which measures them is known to PSE. Yes, they are part of the legal framework in which the utility operates.

e) The intent of the question is not clear.

Building Owners and Managers Association Toronto Interrogatory # 12

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 27

Interrogatory:

a) What are relative weights used for capital and OM&A in the Impact Quantity Index? Please explain fully.

b) Please show the actual calculation which determines the impact of adding safety and reliability figures to the change from normal TFP to the adjusted TFP.

Response:

a) The relative weights for Hydro One's Input Quantity Index are provided below by year. The OM&A weight is calculated by taking the portion of OM&A expenses for that year to total costs. The capital weight is calculated by taking the portion of capital costs for that year to total costs. The sum of the two weights should be 100% because total costs equal the sum of the OM&A expenses and capital costs.

Year	OM&A Weight	Capital Weight
2002	37.4%	62.6%
2003	36.3%	63.7%
2004	34.2%	65.8%
2005	34.4%	65.6%
2006	36.0%	64.0%
2007	38.1%	61.9%
2008	34.8%	65.2%
2009	34.5%	65.5%
2010	35.0%	65.0%
2011	34.2%	65.8%
2012	33.7%	66.3%
2013	35.2%	64.8%
2014	34.7%	65.3%
2015	30.4%	69.6%

b) For the adjustments, this data is available in the working papers provided in Exhibit I-8-Staff-023, which is subject to a confidentiality agreement. The basic idea is the growth rates in the 3-year rolling average of the safety and reliability indexes are added to the unadjusted TFP trend, multiplied by the reported weights, to formulate the adjusted TFP trend.

Building Owners and Managers Association Toronto Interrogatory # 13

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 30

Interrogatory:
What causes the five hundred percent increase from 2009 to 2010 in safety-related expenditures?

Response:
The per cent increase in safety-related costs from 2009 to 2010, prior to restating the 2009 costs as discussed in Exhibit I-BOMA-014, was about 393 per cent (85,752/17,400 - 1 = 3.93).

The increase between 2009 and 2010 safety-related costs was primarily due to costs associated with 1) Safety Training/Meetings, 2) Field Training, and 3) PPE/Supply Chain/Materials. In 2010, these categories amounted to about $65 million.

For costs associated with items 1) and 2) above, the Company started tracking associated costs in Q3-2009 when it converted to SAP – the first full year for tracking these costs was 2010. For PPE/Supply Chain/Materials, Hydro One's tracking methodology changed and the associated costs for 2009 in this category cannot be confirmed.

Building Owners and Managers Association Toronto Interrogatory # 14

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 29

Interrogatory:
What was the rationale for using the funds spent on creating a safe working environment for its workers as a percentage of total spend? Please provide a description of the "safety measures" expenditures, capital and OM&A, shown separately, in each year.

Response:
The percentage of safety spend to the total costs of Hydro One was calculated to provide a weight for the inclusion of the safety metric into the adjusted TFP trend. See page 29 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, where we discuss the rationale for using the percentage weight of safety-related activities to total costs as the basis for the weighting.

Provided below is the breakout for safety related costs. Costs for 2009 and 2010 are restated below to include:

2010:
- $2.19 million for Safety Related Services
- $7.66 million for PPE/Supply Chain/Materials

2009:
- $0.26 million for Journey to Zero Project + DuPont
- $1.44 million for Safety Related Expenses

The impact of these restatements on Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, Table 10 is an increase in the Trackable Safety Related Expenses from $17.4 million to $19.1 million in 2009 and from $85.7 million to $95.6 million in 2010.

Tracking for Safety Training/Meetings and Field Training began in August 2009 when the Company converted to SAP, therefore the first full year of tracking costs for these categories was 2010.

Health Related Expenses

PSE Study

All columns are $M

		2015	2014	2013	2012	2011	2010	2009
HS&E Division								
Rick	Total Expenditures HS&E	31.9	32.1	35.2	36	34.5	32.3	19.2
Rick	Less: Health Spending	3.2	2.9	2.9	2.7	2.5	2.6	1.8
Rick	Less: Environmental Spending	0	0	0	0.8	0.7	1.5	0
Net Safety Division Spending		**28.7**	**29.2**	**32.3**	**32.5**	**31.3**	**28.2**	**17.4**
Related Safety Expenditures								
Bill	Journey to Zero Project + DuPont	0.25	0.002	0.23	0.02	0.03	0.17	0.26
Bill	PPE / Supply Chain / Materials	14.10	12.96	17.10	10.90	11.58	7.66	
Bill	Safety Related Services	1.49	1.27	1.53	0.93	0.59	2.19	1.44
Rick	Safety Training / Meetings	30.5	31.8	29.2	26.2	27.3	28.4	
Rick	Field Training	32.0	34.6	30.2	31.9	29.7	29.0	
Any	Other Related Expenditures							
Other Related Safety Expenditures		**78.3**	**80.6**	**78.2**	**69.9**	**69.2**	**67.4**	**1.7**
Trackable Safety Related Costs		**107.0**	**109.8**	**110.5**	**102.4**	**100.5**	**95.6**	**19.1**

Building Owners and Managers Association Toronto Interrogatory # 15

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02-01 Page: 31

Interrogatory:

a) What has been the number of major Event Days for Hydro One Distribution, in each of the years 2002 to 2016?

b) Please provide Table 11, showing SAIDI numbers in a separate additional column.

Response:

a) Please refer to Exhibit I-9-BOMA-002, part b) for a table of Major Event days.

b)

Table 1: Hydro One Historical SAIFI/CAIDI

Year	SAIFI	SAIFI (3-year Rolling Average)	CAIDI	CAIDI (3-year Rolling Average)	SAIDI
2002	2.57	n/a	3.33	n/a	8.55
2003	2.52	n/a	3.08	n/a	7.75
2004	2.79	2.63	2.32	2.91	6.46
2005	2.62	2.64	2.89	2.76	7.58
2006	2.77	2.73	2.54	2.58	7.03
2007	3.15	2.85	2.57	2.67	8.09
2008	3.01	2.98	2.69	2.60	8.10
2009	2.63	2.93	2.65	2.64	6.96
2010	2.61	2.75	2.73	2.69	7.12
2011	2.57	2.60	2.68	2.68	6.88
2012	2.61	2.60	2.67	2.69	6.98
2013	2.48	2.55	2.73	2.69	6.76
2014	2.67	2.59	2.78	2.73	7.43
2015	2.63	2.59	2.91	2.81	7.65

Building Owners and Managers Association Toronto Interrogatory # 16

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02-01 Page: 36

Interrogatory:
What would Table 17 look like if the Safety Record remained on the 2002 to 2017 record through 2017?

Response:
PSE does not understand what calculation is being suggested.

Building Owners and Managers Association Toronto Interrogatory # 60

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
A-03-01-04 Page: 9

Interrogatory:
Please provide any results the work with peer Canadian utilities to benchmark capital projects.

Response:
Benchmarking studies on Pole Replacement and Substation Refurbishment can be found in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6, Attachment 1, Distribution Unit Cost Benchmarking Study, Pole Replacement and Substation Refurbishment.

Building Owners and Managers Association Toronto Interrogatory # 65

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-01-05 Page: 3

Interrogatory:

a) What value are the forecast total costs for the years 2017-2022 in the benchmarking given that company uses actual costs and costs predicted the model to conduct its benchmarking? What is the most recent actual data for 2017? Please provide June 30th data or May 30th data for 2017.

b) Have you included forecast data for the comparator companies; for some companies?

c) Why were no other Canadian utilities used in the data set? Many of them have large rural areas, etc.

d) Please provide copy of the March 2017 Report. Please provide reference to the benchmarking studies.

Response:

The reference above is pointing to Hydro One's Corporate Organization Chart. Hydro One is interpreting the question as being related to Total Cost Benchmarking study conducted by PSE.

a) The total cost values inserted for Hydro One are provided in the table below for the years 2017 to 2022.

Year	Hydro One Total Costs (CA$, '000)
2017	1,830,140
2018	1,886,033
2019	1,952,626
2020	2,017,330
2021	2,076,276
2022	2,143,156

b) No. Forecast data for the benchmarking sample is not available.

c) Other Canadian utilities do not publicly report Uniform System of Account information, system peaks, and plant addition data to enable inclusion into the sample.

d) Please refer to Exhibit A, Tab 3, Schedule 2, Attachment 2, Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network (Updated with 2016 Actual Hydro One Data and Projections to 2022).

Building Owners and Managers Association Toronto Interrogatory # 67

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-01-05 Page: 10

Interrogatory:

a) What are the limitations on introducing forecast costs into a comprehensive benchmarking study?

b) Where did the total cost data come from for each future year?

Response:

a) The limitations are that the forecasted costs of Hydro One may not be exact. To the extent the actual costs are different from the forecasted costs, this would change the benchmarking score. The forecasted costs use the full spending request. The second limitation is that the benchmarking sample uses historical data. The assumption is that the historical values in the dataset will be indicative of future values and performance. However, performance trends and factors can change over time.

b) The future cost data for Hydro One came from Hydro One and are based on their spending requests. The capital spending is based on the Hydro One capital plan. The OM&A portion of costs during the custom IR period are escalated off the 2018 spending request. Future year OM&A is escalated by an assumed future inflation factor of 2.0% minus an assumed stretch factor of 0.45%.

Consumers Council of Canada Interrogatory # 14

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02 Page 10

Interrogatory:

HON is proposing a Capital In-service Variance Account (CISVA) to track the difference between the revenue requirement associated with the actual in-service capital additions in a test year and the revenue requirement associated with the OEB-approved in-service additions. HON plans to report on this account on an annual basis. Please indicate the level of detail that will be included in the annual report. When will this be filed each year?

Response:

Exhibit A, Tab 3, Schedule 2, page 10 refers to the revenue requirement impact being computed and reported in the variance account on an annual basis. This refers to the recording of the revenue requirement impact in the variance account. The balance of this variance account will be reported in the annual RRR submitted to the OEB. At the time of disposition of the account, data and calculations will be provided to support the balance reported.

Canadian Manufacturers & Exporters Interrogatory # 4

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02 Updated

Interrogatory:
CME is interested in the sensitivity of the capital factor to changes in OM&A and capital additions to rate base.

a) Please provide a version of Table 1 that reflects a 1.55% increase in OM&A in 2019 through 2022 in place of the 1.45% used.

b) Please provide a version of Table 1 that reflects a reduction in capital additions closed to rate base in 2018 of $10 million, with no changes to capital additions in 2019 through 2022.

c) Please provide a version of Table 1 that reflects a reduction in capital additions closed to rate base of $10 million in each of 2018 through 2022.

Response:
This interrogatory references Table 1 in Exhibit A, Tab 3, Schedule 2. The calculations below use the most recent information provided in Table 2 of Exhibit Q, Tab 1, Schedule 1 as the starting point for the analysis.

a) The requested table is provided below.

Table 1

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,666.4	8,026.9	8,430.5	8,960.1	9,326.5
2	Return on Debt	E1-1-1	199.0	208.4	218.9	232.5	242.0
3	Return on Equity	E1-1-1	276.0	289.0	303.5	322.4	335.6
4	Depreciation	C1-6-2	397.1	418.2	433.1	452.1	465.9
5	Income Taxes	C1-7-2	65.4	69.0	71.5	78.9	79.5
6	Capital Related Revenue Requirement		937.5	984.5	1,026.9	1,085.8	1,122.9
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.1)
8	**Total Capital Related Revenue Requirement**		**937.5**	**980.1**	**1,022.3**	**1,080.9**	**1,117.9**
9	OM&A	C1-1-1	579.6	588.6	597.7	607.0	627.3
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,517.1**	**1,568.7**	**1,620.0**	**1,698.6**	**1,745.2**
12	Increase in Capital Related Revenue Requirement			42.6	42.2	58.6	36.9
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.81%	2.69%	3.62%	2.17%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.47%	0.48%
15	**Capital Factor**			**2.34%**	**2.22%**	**3.14%**	**1.70%**

b) The requested table is provided below.

Table 1

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base		7,661.5	8,017.3	8,421.2	8,951.3	9,318.0
2	Return on Debt		199.0	208.2	218.7	232.3	241.8
3	Return on Equity		275.8	288.6	303.2	322.1	335.3
4	Depreciation		396.9	417.8	432.7	451.7	465.5
5	Income Taxes		65.5	69.1	71.5	78.9	79.5
6	Capital Related Revenue Requirement		937.1	983.7	1,026.1	1,085.0	1,122.1
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.0)
8	**Total Capital Related Revenue Requirement**		**937.1**	**979.3**	**1,021.5**	**1,080.1**	**1,117.0**
9	OM&A		579.6	584.0	588.3	592.8	608.0
10	Integration of Acquired Utilities					10.7	
11	**Total Revenue Requirement**		**1,516.8**	**1,563.3**	**1,609.8**	**1,683.6**	**1,725.0**
12	Increase in Capital Related Revenue Requirement			42.2	42.2	58.6	36.9
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.78%	2.70%	3.64%	2.19%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.32%**	**2.23%**	**3.17%**	**1.71%**

c) The requested table is provided below.

Table 1

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base		7,661.5	8,012.4	8,406.8	8,927.6	9,285.5
2	Return on Debt		199.0	208.1	218.3	231.7	241.0
3	Return on Equity		275.8	288.4	302.6	321.2	334.1
4	Depreciation		396.9	417.6	432.1	450.7	464.2
5	Income Taxes		65.5	69.2	71.8	79.1	79.7
6	Capital Related Revenue Requirement		937.1	983.3	1,024.8	1,082.7	1,119.0
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.0)
8	**Total Capital Related Revenue Requirement**		**937.1**	**978.9**	**1,020.2**	**1,077.9**	**1,114.0**
9	OM&A		579.6	584.0	588.3	592.8	608.0
10	Integration of Acquired Utilities					10.7	
11	**Total Revenue Requirement**		**1,516.8**	**1,562.9**	**1,608.5**	**1,681.3**	**1,722.0**
12	Increase in Capital Related Revenue Requirement			41.8	41.3	57.7	36.1
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.75%	2.64%	3.59%	2.15%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.29%**	**2.17%**	**3.11%**	**1.67%**

Canadian Manufacturers & Exporters Interrogatory # 5

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02 Updated

Interrogatory:

a) Will the capital factor that is calculated and shown in Table 1 be updated annually at the same time that the inflation factor is updated, or will the capital factor be determined for each of 2019 through 2022 as part of this proceeding and then not altered regardless of the change in the capital related revenue requirement due to changes from forecast in capital additions? If this cannot be confirmed, please explain fully.

b) If the capital factor is not proposed to be updated on an annual basis for 2019 through 2022, please confirm that the capital factor will not be altered regardless of the change in the capital related revenue requirement due to changes in the cost of capital parameters as proposed by Hydro One for 2021 and 2022. If this cannot be confirmed, please explain fully.

Response:

a) As described on page 5 of Exhibit A, Tab 3, Schedule, the capital factor for 2019 and 2020 will remain unchanged once finalized using OEB-approved values in the Draft Rate Order of this proceeding. In its 2021 annual update application, Hydro One will subsequently update the calculations for the 2021 and 2022 capital factors to reflect the applicable 2021 cost of capital parameters.

b) See a).

Canadian Manufacturers & Exporters Interrogatory # 6

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02 Updated

Interrogatory:

a) Does the rate base and capital related revenue requirement shown in Table 1 include the rate base and capital related revenue requirement associated with cash working capital?

b) If yes, please explain why the capital factor should be influenced by the cash working capital, when the capital factor is designed to meet specific circumstances associated with the proposed capital investments set out in the DSP.

c) Please provide a version of Table 1 that removes the cash working capital component of rate base and capital related revenue requirement and adds the revenue requirement impact below line 8 (similar to OM&A) while maintaining the calculation of the capital factor using line 8 (which now excludes the revenue requirement associated with cash working capital) and the total revenue requirement from the previous year.

Response:

a) Yes.

b) As stated on page 5 of Exhibit A, Tab 3, Schedule 2, the Capital Factor is the percentage change in the total revenue requirement "that is not otherwise recovered from ratepayers" that is attributable to new capital placed in-service each year of the Custom IR term. It excludes the capital related revenue requirement that is captured by the I-X portion of the Revenue Cap Index. The funding for the working capital allowance is being provided through the I-X portion of the Revenue Cap Index.

c) As noted in part (b), the revenue requirement associated with the working capital allowance is already removed from the capital factor when the I-X portion of costs are removed from the calculation as outlined on pages 5-7 of Exhibit A, Tab 3, Schedule 1. This is also shown in line 14 of Table 1 of the same Exhibit.

Energy Probe Research Foundation Interrogatory # 7

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02 Page: 6

Interrogatory:
Please explain how Hydro One will ensure that its proposed capital factor does not over-recover the cost of capital expenditures.

Response:
Hydro One has proposed a Capital In-service Variance Account to protect ratepayers from over-recovery in the event that Hydro One does not achieve its planned in-service capital targets. For further details please see page 10 of Exhibit A, Tab 3, Schedule 2.

Vulnerable Energy Consumers Coalition Interrogatory # 10

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02

Interrogatory:
a) Please confirm that the proposed Custom Capital Factor (CCF) is based on the forecast present in Table 1 (page 6). That is, does the capital factor vary over time from the value shown in Table 2?

b) Given that capital expenditures are completely within the control of management (except for emergency repairs) why is it reasonable to calculate the proposed capital factor on a forecast rather than actual basis (i.e. as a trailing adjustment)?

c) If Hydro One used actual capital spending, capped at the forecast expenditures would the CISVA Account be necessary (i.e. would the outcome for rates be similar or the same)?

Response:
a) The CCF is based on the forecast present in Table 1. As noted in response to Exhibit I-7-VECC-5, Hydro One proposes to update the calculations for the 2021 and 2022 capital factors to reflect updated cost of capital parameters.

b) As noted on page 24 of the OEB's Handbook for Utility Rate Applications, under Custom IR "rates are set for five years considering a five-year **forecast** of the utility's costs". [Emphasis added]

c) As noted in (b) the OEB sets rates on the basis of forecast costs.

Vulnerable Energy Consumers Coalition Interrogatory # 11

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02

Interrogatory:
a) What is the theoretical linkage supporting the productivity factor as part of the CCF?

b) What is the relationship between the CCF and customer growth?

c) What is the relationship between the CCF and capital investment related reliability outcomes?

Response:
a) The reduction of the costs in the CCF by the productivity factor is driven by OEB policy. On page 25 of the OEB's *Handbook for Utility Rate Applications*, the OEB states that "incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast)." This is also consistent with the OEB's findings that the stretch factor should apply to capital costs in the Custom IR proceeding for Toronto Hydro-Electric System Ltd. (EB-2014-0016).

b) See Hydro One's response part (a) of Exhibit I-8-Staff-21.

c) As stated in Exhibit A, Tab 3, Schedule 2, the CCF is designed to ensure that the total revenue resulting from the proposed Custom IR is able to meet Hydro One's proposed capital investments set out in Hydro One's Distribution System Plan (Exhibit B1, Tab 1, Schedule 1). The reliability outcomes that are expected to be achieved by Hydro One's planned capital investments are discussed in Section 2.4 of the Distribution System Plan.

Vulnerable Energy Consumers Coalition Interrogatory # 12

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02

Interrogatory:

a) Please provide a table for the period 2010 through 2022 which shows the following for distribution plant:
   i. The total depreciation expense in the year;
   ii. The actual capital spending in the year;
   iii. Mid-year net plant additions;
   iv. Year-end plant additions;
   v. The ratio of year-end depreciation to year-end plant in-service; and
   vi. CRA CCA allocated to distribution in the year.

Response:

a)
   i. Total depreciation Expense as evidenced in Exhibit Q-01-01 below:

Description	Historic				Bridge	Test				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Total Depreciation Expenses	313.0	336.2	349.0	359.8	362.6	383.9	406.4	418.9	438.3	453.5

   ii. Capital expenditures as evidenced in Exhibit Q-01-01 below:

Description	Historic				Bridge	Test				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capital Expenditures	637.0	647.5	678.3	694.2	661.4	628.1	736.4	699.3	711.0	796.5

iii. 2013 to 2022 Mid-Year Plant Additions, shown below, calculated by taking average plant additions over current and prior year (consistent with the calculation of rate base):

Description	**Historic**				**Bridge**	**Test**				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Mid-year Plant Additions	641.8	676.5	689.5	705.1	653.3	643.5	695.2	751.9	726.6	744.5

iv. 2013 to 2022 Year-end Plant Additions as per Exhibit Q-01-01

Description	**Historic**				**Bridge**	**Test**				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Plant Additions	729.3	623.7	755.3	654.8	651.8	635.1	755.2	748.5	704.6	784.4

v. Year End Depreciation to Year End Plant Additions Ratio

Description	**Historic**				**Bridge**	**Test**				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Ratio % (i/ iv)	42.9	53.9	46.2	54.9	55.6	60.4	53.8	56.0	62.2	57.8

vi. 2013 to 2022 CCA and CEC as per Exhibit Q-01-01

Description	**Historic**				**Bridge**	**Test**				
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
CCA/CEC	425.7	439.5	372.2	412.0	422.7	432.5	455.2	473.9	490.0	513.0

Vulnerable Energy Consumers Coalition Interrogatory # 13

Issue:

Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:

A-03-02

Interrogatory:

a) The CCF averages to 2% per year over the life of the rate program. Given an objective of rate stability (and if the adjustment is, apparently, to be made on a forecast not actual basis) why would it not be preferable to simply adjust the revenue requirement by the average of 2% per annum for capital additions over the rate program period?

Response:

a) As stated on page 24 of the OEB's *Handbook for Utility Rate Applications*, rates are set for five years based on a forecast of a utility's costs under the Custom IR method. The value of the proposed CCF is appropriately set based on a detailed five-year forecast of Hydro One's capital requirements.

Vulnerable Energy Consumers Coalition Interrogatory # 14

Issue:
Issue 9: Are the values for the proposed custom capital factor appropriate?

Reference:
A-03-02 Page: 8

Interrogatory:
a) Please explain how the CCF is adjusted for the inclusion of the acquired utilities in 2021

Response:
a) As noted on page 8 of Exhibit A, Tab 3, Schedule 2, the incremental rate base of $168.4 million associated with the assets of the acquired utilities is added to Hydro One's 2021 rate base in line 1 of Table 1 of that Exhibit. The resulting revenue requirement associated with that additional rate base is also reflected in lines 2-6 and flows through to the capital factor as described on pages 5-7 of Exhibit A, Tab 3, Schedule 2.

Canadian Manufacturers & Exporters Interrogatory # 12

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-05-02-01 Updated

Interrogatory:

a) Please explain the significant difference in the 2015 capital cost shown in the live excel model of $934,109,550 and the figure of $706,792,807 shown in Table 2 in the July 2016 Report to the Ontario Energy Board on Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update from Pacific Economics Group Research, LLC.

Response:

a) The difference is due to the change in reported high voltage capital additions for 2013, 2014, and 2015. Hydro One originally reported much higher high voltage additions. The live Excel model uses the revised numbers, whereas the July 2016 Report uses the originally reported numbers. The 4GIR PEG model takes reported capital additions and subtracts out the high voltage additions in the calculations. Therefore the capital costs for Hydro One found in Exhibit A, Tab 5, Schedule 2, Attachment 1 are significantly higher; they use the revised high voltage additions, which are considerably lower than those originally reported.

Energy Probe Research Foundation Interrogatory # 8

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-01 Page: 22 Table 6

Interrogatory:

Are the productivity savings in Table 6 cumulative or incremental? For example, is Hydro One proposing an additional $70.5 million in productivity savings in 2019 or is it proposing an additional $7.3 million in savings from the $63.2 million of savings achieved in 2018?

Response:

The productivity savings referenced in Exhibit A, Tab 3, Schedule 1, p.22, Table 6 have been updated in Exhibit I-25-Staff-123. The savings are presented relative to a 2015 baseline and measured on a unit basis.

In the example noted above (and with reference to the updated Table), Hydro One would have to achieve lower unit costs in 2018 relative to baseline to generate $70 million of savings. In the following years Hydro One would have to ensure continuity of those lower unit costs plus an incremental benefit to achieve $72 million savings in 2019 and $82 million in 2020 etc.

Energy Probe Research Foundation Interrogatory # 9

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
A-03-01 Page: 22 Table 6

Interrogatory:
Preamble: In Hydro One's previous distribution rate application – EB-2013-0416, 2015-2019 rates – the utility estimated that it would achieve more than $100 million annually in productivity savings between 2015 and 2019. When the test year, 2014, was included, those savings amounted to more than $728 million in savings.

a) Can Hydro One provide an update on the forecasted savings from its previous rate application?

b) Are those productivity savings included in this application?

c) Are the savings detailed in Hydro One's current application in addition to those laid out in the previous rate application?

Figure 1:

Distribution Productivity Savings

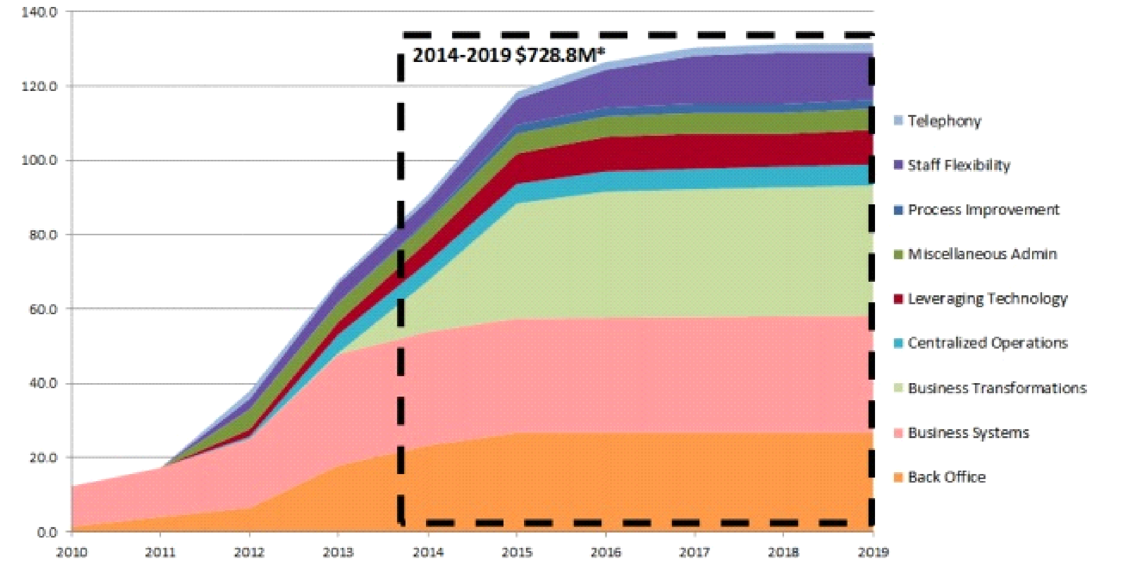


Table 2:

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

Table 1:

Impact to Revenue Requirement Inclusive and Exclusive of Productivity Savings

	2013 Actual	2014 Bridge	2015 Test	2016 Test	2017 Test	2018 Test	2019 Test
OM&A per application	610,622,850	581,316,339	564,304,626	610,181,582	613,969,206	603,863,604	600,001,194
YoY growth		-4.8%	-2.9%	8.1%	0.6%	-1.6%	-0.6%
Add: Productivity Savings	50,378,620	69,418,195	95,332,361	102,698,023	106,293,228	106,581,261	106,632,090
OM&A without Productivity	661,001,470	650,734,534	659,636,986	712,879,605	720,262,434	710,444,865	706,633,284
YoY growth		-1.6%	1.4%	8.1%	1.0%	-1.4%	-0.5%

Response:

Please refer to Exhibit I-21-SEC-033.

Energy Probe Research Foundation Interrogatory # 10

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-01 Page: 22 Table 6

Interrogatory:

Please explain how Hydro One plans to track actual productivity savings against its forecast of productivity savings, and how it plans to differentiate between productivity savings and cost savings in future years.

Response:

Please refer to Exhibit I-25-Staff-123.

Witness: LOPEZ Chris

Energy Probe Research Foundation Interrogatory # 11

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02 Page: 10

Interrogatory:

a) Please explain the method Hydro One proposes to use in tracking "verifiable productivity gains" during the Custom IR term.

b) Please provide a numerical example using hypothetical numbers.

Response:

a) The method used to track verifiable productivity savings is described in part (b) of Hydro One's response to Exhibit I- 25-Staff-123.

b) A numerical example is provided below.

In Service Additions Target (includes embedded productivity) **(A)**	$100
Actual In Service Additions Achieved **(B)**	$ 96
Incremental verifiable Capital-related productivity **(C)**	$ 3
Deemed In Service Additions **(D) → (B) + (C)**	$ 99
In Service Ratio **(D) / (A)**	99%

Verifiable capital-related productivity savings reflect the sum of capital productivity savings and the capital allocated portion of productivity savings associated with Common Corporate costs. Incremental verifiable capital-related productivity savings reflect verifiable productivity savings above amounts shown in Exhibit I- 25-Staff-123.

School Energy Coalition Interrogatory # 10

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01

Interrogatory:

With respect to the retainer of Power System Engineering to carry out the TFP study:

a) Please provide the agreement between the Hydro One and the consultant, including all amendments.
b) Please provide the scope of work or other documents describing the initial instructions to the consultant, if they are not included in (a).
c) Please provide all written instructions to the consultant by the Hydro One or by counsel or others on other behalf, including but not limited to suggestions for edits to early drafts.

Response:

a) Please refer to Exhibit I-10-SEC-010, attachments.

b) Please refer to a) above.

c) In order to prepare its independent benchmarking study, Power System Engineering met regularly with Hydro One staff. Discussions included detailed aspects of the TFP. Throughout this process, Hydro One was afforded the opportunity to discuss and clarify preliminary observations made by Power System Engineering. These discussions and commentary occurred over a period of several months, took several formats (oral discussions, emails and telephone meetings). Hydro One had no decision-making role regarding the content or the conclusions that were reached by Power System Engineering. The underlying information that Power System Engineering has relied on for purposes of its reports is not a matter within Hydro One's domain or control. The requested compilation of all correspondence, exchanges, discussions that took place between Hydro One employees and Power System Engineering would take an inordinate effort and cost without any real or apparent purpose to the Board's consideration and review of the issues in this proceeding. Hydro One therefore declines to provide the requested information. Neither Hydro One nor its counsel provided any instructions to Power System Engineering that would in any way impair or affect the objectivity and independence of the author's stated conclusions and findings. If SEC wishes to test the objectivity and independence of Power System Engineering and the conclusions that they have reached, this can occur through questions asked to Power System Engineering witnesses, and the testing of whether, or not, Power System Engineering's independence and objectivity was at any time impaired by the process which Power System Engineering used to prepare its reports.

CONTRACT STANDARD

Class	Number	Date
A	29	2011

HYDRO ONE INC.
OR ONE OF ITS SUBSIDIARY CORPORATIONS

STANDARD COMMERCIAL CONDITIONS FOR CONSULTING AND PROFESSIONAL SERVICES

October 2011

CONTENTS

1. <u>**Definition of Terms**</u>

The following terms, wherever used in any contract document, shall mean:

(1) "Conflict of Interest" - means, but is not limited to, any situation or circumstance where, in relation to the performance of its obligations under this contract, the Consultant's other commitments, relationships or financial interests (i) could or could be seen to exercise an improper influence over the objective, unbiased and impartial exercise of its independent judgement; or (ii) could or could be seen to compromise, impair or be incompatible with the effective performance of its obligations under this contract;;

(2) "Consultant" – means the individual, partnership or corporation who has been retained by the Purchaser to provide consulting and/or professional services;

(3) "Contract Price" - the stipulated value or sum of value(s) of the fixed price(s) or upset maximum price(s) for the Work (or any portion thereof) set forth in the contract documents as amended by any Instruction Notice. In the case of time and material contracts, "Contract Price" shall mean the product of the rates

stipulated in the contract multiplied by the estimated number of units of time the rates represent for the term of the contract, subject to any subsequent adjustments for : (i) actual eligible units of time incurred; and, (ii) upset maximum amounts. Contract Price excludes the GST/HST.

(4) "FIPPA" - means the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended;

(5) "Goods and Services Tax" or "GST" means the federal Goods and Services Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended (the "Excise Tax Act"), and includes the additional tax payable under sub-section 165(2) of the Excise Tax Act in respect of a supply made in a participating province;

(6) "Harmonized Sales Tax" or "HST" - means GST payable for a supply made in a participating province. Ontario is a participating province effective July 1, 2010;

(7) "Hydro One Home Location Area" – means an area within a 75 kilometer radius of 483 Bay Street, Toronto, Ontario M5G 2P5, and such other Hydro One locations in Ontario designated as such in any of the documents forming part of this contract;

(8) "Instruction Notice" – a formal executed written document issued by the Purchaser's representative formally amending the Purchase Order in any respect. Any other document purporting to be an instruction notice will be considered invalid;

(9) "Personal Information" means recorded information about an identifiable individual or that may identify an individual;

(10) "Proposal" – means the Consultant's submission in response to the Purchaser's Request for Proposal Documents.

(11) "Request for Proposal Document(s)" or "RFP" - the documents issued by the Purchaser calling for tenders, responses, or proposals for the performance of the Work or for the prequalification to perform the Work, as further stated in the said documents;

(12) "Purchaser" – means Hydro One Inc. or one of its subsidiaries, whichever of those corporations has been designated in a contract document;

(13) "Record" - any recorded information, including any Personal Information, in any form: (a) provided by the Purchaser to the Consultant, or provided by the Consultant to the Purchaser, for the purposes of this contract; or (b) created by the Consultant in the performance of this contract; and shall include or exclude any information specifically described in the purchase order;

(14) "Unfair Advantage" - any conduct, direct or indirect, by the Consultant at the procurement/bidding stage that may result in gaining an unfair advantage over other parties in the procurement/bidding process, including but not limited to (i) possessing, or having access to, information in the preparation of its Proposal that is confidential to the Purchaser and which is not available to other competitors, (ii) communicating with any person with a view to influencing, or being conferred preferred treatment in, the procurement process, or (iii) engaging in conduct that compromises or could be seen to compromise the integrity of the procurement process and result in any unfairness, including, without limitation, conduct, agreement, or concerted practice between the Consultant and another company or person to, among other things, create a fake bid/submission for comparative purposes, or require a competitor to refrain from bidding, or require a competitor to bid in a certain manner, or share details about their bid, including how they intend to bid; and,

(15) "Work" - all labour, materials, equipment, deliverables, documentation, services, tools, supplies, and acts required to be done or supplied.

2. **<u>Contract Documents and Order of Precedence</u>**

(a) The contract documents shall consist of (1) the Purchaser's Purchase Order ("Purchase Order"); (2) Clarification Documents (if any) agreed to and incorporated into the Purchase Order; (3) Insurance Requirements' (4) Special Terms and Conditions; (5) this Contract Standard (A-29-2011); (6) the Consultant's Proposal and (7) the Request for Proposal Documents (other than those listed above). These contract documents shall, to the extent of any inconsistency or conflict, take precedence in the order in which they are named.

Appendices and addenda to any contract document shall be considered part of such document. The contract documents form this contract.

(b) These documents are subject to subsequent amendments to this contract, in the form of Instruction Notices or Change Orders, which shall take precedence over the documents amended thereby.

(c) No agent, employee or other representative of the Purchaser has authority to make any promise, agreement or representation not incorporated into a contract document, and no promise, agreement or representation whenever made shall bind the Purchaser unless so incorporated formally through the Instruction Notice or Change Order.

(d) The contract documents and the Work as specified therein shall be interpreted to include all Work reasonably required to provide a result that is fit for the Purchaser's purposes.

3. **The Purchaser's Representative**

The Purchaser shall inform the Consultant as to the identity of its authorized representative, to whom all correspondence, reports and documents shall be addressed. No acceptance, instruction, approval or statement by the Purchaser's authorized representative or by any other representative of the Purchaser shall relieve the Consultant from responsibility for proper performance of the Work.

4. **FIPPA Records and Compliance**

(a) The Consultant and the Purchaser acknowledge and agree that FIPPA applies to and governs all Records and may require the disclosure of such Records to third parties. Furthermore, the Consultant agrees:

(i) to keep Records secure;

(ii) to provide Records to the Purchaser within seven (7) calendar days of being directed to do so by the Purchaser for any reason including an access request or privacy issue;

(iii) not to access any Personal Information unless the Purchaser determines, in its sole discretion, that access is permitted under FIPPA and is necessary in order to perform the Work;

(iv) not to directly or indirectly use, collect, disclose or destroy any Personal Information for any purposes that are not authorized by the Purchaser;

(v) to ensure the security and integrity of Personal Information and keep it in a physically secure and separate location safe from loss, alteration, destruction or intermingling with other records and databases and to implement, use and maintain the most appropriate products, tools, measures and procedures to do so;

(vi) to restrict access to Personal Information to those of its directors, officers, employees, agents, partners, affiliates, volunteers or subcontractors who have a need to know it for the purpose of providing the Work and who have been specifically authorized by the Purchaser authorized representative to have such access for the purpose of providing the Work;

(vii) to implement other specific security measures that in the reasonable opinion of the Purchaser would improve the adequacy and effectiveness of the Consultant's measures to ensure the security and integrity of Personal Information and Records generally; and,

(viii) that any confidential information supplied to the Purchaser may be disclosed by the Purchaser where it is obligated to do so under FIPPA, by an order of a court or tribunal or pursuant to a legal proceeding;

(b) The provisions of this Section shall prevail over any inconsistent provisions in this contract.

(c) The provisions of this Section shall survive any termination, cancellation, or expiry of this contract.

(d) The Purchaser may immediately terminate this contract upon giving notice to the Consultant where the Consultant breaches any provision in this Section FIPPA Records and Compliance.

5. **Pricing**

(a) The Contract Price shall be as referenced in the Purchase Order. Unless expressly stated otherwise in the Purchase Order, as part of the Contract Price, the fixed price, upset maximum (not to exceed) price and/or rates shall be deemed to be gross prices and/or rates. For greater certainty, as part of the Contract Price, the said gross prices and/or rates will include all applicable taxes (except for GST/HST), premiums, levies, duties, and other charges of every kind attributable to the Work, whether or not they are statutory or otherwise, including, without limitation, in relation to the following: insurance; Workplace Safety and Insurance Board (WSIB) or those of a similar body; payroll; health plan; dental plan; drug plan; employment insurance; vacation pay; sick time; bonus pay; Canada Pension Plan; any other pension plan; and, tax equalizations.

(b) Only the GST/HST shall be shown separately as an extra to the Contract Price.

(c) The Consultant's prices and/or rates in (a) above shall be deemed to compensate the Consultant for all corporate, executive, and management expenses, general administration expenses, including the services of a project administrator (unless otherwise expressly specified in writing and referenced in the purchase order), accounting, employee relations, clerical staff, secretarial support, normal stationery and office supplies, local telephone, rent, utilities, taxes, depreciation, and Consultant's fees.

(d) Consultant personnel designated as manager or above, including Project Manager or similar title or function, shall not be charged to the Work unless they are engaged in making a substantial direct technical contribution thereto, or unless otherwise specified in writing. Any effort which contemplates such charges shall require the Purchaser's prior written authorization.

(e) The following applies to upset maximum (not to exceed price) pricing and time and material pricing. It does not apply to fixed prices:

(i) The use of overtime hours on the Work shall be subject to the Purchaser's prior written approval. Overtime hours shall be compensated at straight time hourly rates. The Purchaser shall be entitled to a reasonable reduction in overhead rates to take the increase in billable hours into account.

(ii) The services of other consultants shall not be employed without the prior written approval of the Purchaser. Where such approval is obtained, the Consultant shall be reimbursed, without mark-up of cost, at the per diem or hourly rate charged by the other consultant(s).

(ii) Contract staff, employed at the Consultant's premises and under its direct supervision, shall be reimbursed at the per diem or hourly rate cost to the Consultant, without mark up, unless otherwise agreed upon in writing with the Purchaser.

(f) If Purchase Order expressly allows for recoverable expenses, the following expenses will be recoverable at cost, provided they are necessary and reasonable, and were directly and properly incurred for the performance of the Work:

(i) traveling and lodging expenses for Consultant personnel while away from their home office (as established for the purpose of this contract), provided that the anticipated expenses are approved in writing in advance by the Purchaser. No traveling or lodging expenses will be reimbursable if the Consultant has an office within the Hydro One Home Location Area and Consultant personnel is required to travel to any location within the Hydro One Home Location Area;

(ii) special drawings or reproduction charges;

(iii) printing or copying of documents for delivery to the Purchaser in excess of 15 sets; and,

(iv) other items approved in advance in writing by the Purchaser.

Recoverable travel-related expenses and other expenses shall also be subject to the Purchaser's *Travel and Expense Guidelines* in effect from time-to-time.

(g) Under no circumstances will any expenses be recoverable by the Consultant from the Purchaser, either directly or indirectly, for any hospitality, incidental, or food or beverage expenses incurred by Consultant personnel, or anyone acting on behalf of Consultant, including but not limited to expense in respect of:

(i) meals, snacks and beverages;
(ii) gratuities;
(iii) laundry, dry cleaning and valet services;
(iv) dependant care; and,
(v) personal telephone calls.

6. **Accounts and Right to Audit**

The Consultant shall keep proper accounts and records of the Work in form and detail satisfactory to the Purchaser. Such accounts and records, including invoices, receipts, time cards and vouchers shall at all reasonable times be open to audit, inspection and copying by the Purchaser. Accounts and records shall be preserved and kept available for audit until the later of: (i) expiration of two years from the date of completion of the Work and all warranty obligations under this contract; and, (ii) the date of early cancellation of the Work under Section 25 or termination of the Work under Section 27hereof.

7. **Elimination of the Ontario Retail Sales Tax**

The Ontario Retail Sales Tax ("ORST") was eliminated effective July 1, 2010. The Consultant covenants and agrees that any cost savings as a result of the elimination of the ORST will be fully reflected in the amounts charged to the Purchaser under this contract. The Consultant will provide such information as the Purchaser may reasonably request to confirm that the full effect of all savings as a consequence of the elimination of the ORST are reflected in the prices, fees, and costs charged to the Purchaser.

8. **Proprietary Rights, Confidentiality**

(a) Both parties retain all rights to methodology, knowledge, and data brought to the Work and used therein. No rights to proprietary interests existing prior to the start of the Work are passed hereunder other than rights to use same as provided for below. The Consultant shall not knowingly incorporate into the Work any data, software or hardware the use of which by the Purchaser violates the proprietary rights of third parties.

(b) All right, title, and beneficial ownership interests to all intellectual property, including copyright, of any form, including, without limitation, discoveries (patented or otherwise), software, data (hard copies and machine readable) or processes, conceived, designed, written, produced, developed or reduced to practice in the course of the Work shall irrevocably vest in and remain with the Purchaser. The Consultant shall not do any act which may compromise or diminish the Purchaser's interests as aforesaid.

(c) The Consultant grants to the Purchaser a non-exclusive, paid-up, irrevocable, perpetual license to use any data and other proprietary items incorporated into the Work by the Consultant hereunder. Provided it is part of the Consultant's proposal and incorporated into this contract, the Consultant may reserve the right to incorporate into the Work data or other proprietary property for the use of which the Consultant wishes to charge a fee stipulated in the said proposal and incorporated into this contract. If the Consultant's proposal does not contain the fee, the Consultant shall be deemed to have waived any such fee. The Purchaser shall have the right to exploit such data and property and to license same to third parties provided that such licenses contain reasonable reservations of proprietary rights in favor of the Consultant (which may be included in a general reservation, but shall contain the same order of legal protection as the Consultant uses when distributing such data or property to third parties) or provided the use of same does not reveal information proprietary to the Consultant.

(d) Except as required in the performance of the Work or as authorized in writing by the owner, each party shall keep confidential all personal, customer, and proprietary information of the other ("confidential information"), including, without limitation, all unpublished business and technical information, papers, or records, however produced. The Consultant remains responsible if any confidential information is disseminated to its sub-consultant. These obligations of confidentiality shall survive completion and/or early termination or cancellation of this contract and shall apply for a period of five years from the date of the last invoice submitted by the Consultant hereunder. In addition to the foregoing, if requested by the Purchaser, the Consultant shall sign a more extensive and stringent confidentiality agreement. In all cases, if requested by the Purchaser, the Consultant agrees to obtain for the Purchaser the written agreement of the Consultant's employees, sub-consultants, and agents to protect all confidential information.

9. **Purchaser's Code of Business Conduct; Conflict and Interested Persons**

(a) The Consultant acknowledges and agrees that the Purchaser's directors, officers, employees, agents, representatives, and business partners are bound by the Purchaser's Code of Business Conduct.

(b) The Consultant will not take any action that would cause the Purchaser or any of its directors, officers, employees, agents, representatives, or business partners to be in breach of any of the obligations set out in Hydro One's corporate Code of Business Conduct. A current copy of the code may be reviewed by downloading the electronic document by following the appropriate link at the following hyperlink: http://www.HydroOne.com/CodeofConduct

(c) In connection with any of the Work under this contract, the Consultant covenants and agrees, not to offer or give directly or indirectly to any of the Purchaser's employees or representatives, or their immediate family members (including their common law relationships) known to the Consultant to the best of its knowledge and belief, each of the foregoing persons an "Insider", collectively "Insiders", any of the following:

(i) any form of bribe or kickback;

(ii) gifts of cash, gift certificates, services, discounts, or loans;

(iii) any gift, entertainment, or similar type of benefit that does not serve a legitimate business purpose; or

(iv) any gift, entertainment, or similar type of benefit that may compromise or appear to compromise their ability to make business decisions in the best interest of the Purchaser.

(d) The Consultant further represents, warrants, and covenants that, at the commencement of this contract, and throughout its term, to the best of the Consultant's knowledge and belief, no Insider has (or will have) an interest (whether directly or indirectly, or personal, or financial), in the supplies, work, or business to which this contract relates, or in any portion of the profits thereof, or in any monies to be derived therefrom ("Insider's Interest"); however, there is no breach of the foregoing where:

(i) at the time of entering into this contract, the Consultant has disclosed all relevant facts known to it concerning the Insider's Interest, and the Purchaser has provided the Consultant with a written determination, made at the Purchaser's sole and absolute discretion, that the Insider's Interest:

A. does not have potential for real or perceived Conflict of Interest, or

B. has a potential for real or perceived Conflict of Interest but it can be managed in a way that protects the integrity and reputation of the Purchaser, and would withstand the test of reasonable and independent scrutiny, and a suitable method of monitoring and managing such real or perceived conflict has been determined and is implemented.

(ii) the Consultant is a publicly-traded company that offers its registered securities to the general public and the Insiders, collectively, have an insignificant interest in the stock of that company, not to exceed a total of five per cent of the outstanding stock of the company.

10. **<u>Conflict of Interest in Performance of Work and Unfair Advantage</u>**

(a) The Consultant represents and warrants that there is no Conflict of Interest between the performance of the Work outlined in the contract documents and its performance of Work and provision of services to other customers, and this warranty shall survive the execution of this contract.; during the performance of the Work, should any such Conflict of Interest be discovered, the Consultant covenants to immediately advise Purchaser of same, and Purchaser may, at its discretion, terminate this contract, or any part thereof, for cause under Section 10 herein.

(b) The Consultant further represents, warrants, and covenants that, prior to the award of this contract, to the best of the Consultant's knowledge and belief, no Unfair Advantage existed. Should the Purchaser discover the Consultant's failure to have disclosed all material details in connection with any Unfair Advantages at the procurement/bidding stage, the Purchaser may, at its discretion, terminate this contract, or any part thereof, for cause under Section 10 herein.

11. **<u>Surety Bonds – Performance, Labour and Material Payment; Other Security</u>**

(a) Surety Bond - At Purchaser's request, at any time, and from time to time, the Consultant may be required to furnish one or more surety bonds (being a performance bond(s) and/or a labour and material payment bond) in a form satisfactory to the Purchaser and in an amount up to 100 percent of the Contract Price.

The surety shall be acceptable to the Purchaser and licensed to issue such surety bonds in the Province of Ontario. The Consultant shall maintain the surety bonds in good standing until the fulfillment of its obligations under this contract.

(b) Other Security - At Purchaser's request, at any time, and from time to time, the Consultant may be required to furnish other security for contract performance, in a form and amount satisfactory to the Purchaser, such as a guarantee by a parent company (if applicable), a bank letter of credit, bank guarantee, a monetary deposit, or personal property security documentation.

(c) Reimbursement for Cost of Surety Bonds –

(i) If not requested for in the Tendering Documents, or,

(ii) if requested in the Tendering Documents and the cost thereof is shown separately in the Tender,

then following the issuance of a surety bond, the Consultant will be reimbursed for the cost thereof (if any, and without mark-up of cost by Consultant) at rates no more than the prevailing industry rates, 30 days after receipt of actual invoice accompanied by evidence of payment to the surety. After payment of the initial premium, the Consultant shall at its expense maintain the surety bond, and/or other security for contract performance in good standing for the duration of this contract, until fulfillment of its obligations under this contract. There will be no reimbursement of costs in relation to surety bonds in other circumstances or for the costs of any other security.

(d) Failure to Furnish Surety Bonds or Other Security - Failure to furnish the surety bonds, or other security within two weeks from the date of request, made at any time, therefor by the Purchaser, shall make any award of contract by the Purchaser subject to withdrawal and shall also entitle the Purchaser to the payment of any damages it may suffer as a result. If this contract has already commenced, the failure to furnish such surety bonds or other security will, at the Purchaser's sole discretion, entitle the Purchaser to terminate this contract for cause.

12. **Inspection and Warranty**

The Purchaser's authorized representative shall have the right, without any obligation to exercise that right, to inspect the Work at all times and may reject any part thereof which is found to be not in accordance with this contract and any applicable standards, including without limitation, applicable professional and safety standards, and any standards customary in the industry, and those imposed by law, including statutes, regulations, orders, guidelines, and judgments. However, the exercise by the Purchaser of its right to inspect shall not be construed to diminish any of the Consultant's duties and obligations under this contract. Any of the Work so rejected shall be promptly redone by the Consultant at its expense. This shall include, but not be limited to, all drawings and data prepared by the Consultant under this contract which are found, within a period of one year from date of transmittal to the Purchaser, to be incomplete or inaccurate due to a failure to comply with said standards.

13. **Escorted Access**

(a) If any of the Work or services provided pursuant to this contract requires entry to one or more of the Purchaser's transmission stations, switching stations, distribution stations or control centres by the Consultant or its sub consultants or any person providing services to, or acting on behalf of, the Consultant or its sub consultants (collectively, the "Entrants"), no Entrant shall be permitted entry to any of the said premises unless accompanied at all times by an employee of the Purchaser or another person appointed by the Purchaser to provide such accompaniment. It shall be the responsibility of the Consultant to arrange such accompaniment, and the Consultant shall ensure that no Entrant shall enter or attempt to enter the said premises without such accompaniment. The Purchaser may, at its sole discretion, waive in writing the requirement for the Consultant to be escorted when entering transmission stations, switching stations, and distribution stations.

(b) The Consultant shall obey all rules and regulations established by the Purchaser regarding the premises to which the Consultant has access and projects on which the Consultant performs the Work.

14. **Safety**

If the Work includes field work, the Consultant shall comply with all relevant safety rules and regulations, including, without limiting the generality of the foregoing, those established by the Purchaser.

15. **Purchaser's Limitation of Liability**

Subject to all other exclusions and limitations anywhere in the contract documents, the Purchaser's maximum liability to the Consultant, or anyone claiming through the Consultant, shall not exceed an amount equal to the lesser of: (i) the Contract Price, and (ii) one hundred thousand dollars ($100,000). In no event shall the Purchaser be responsible for any losses or damages that are indirect, consequential, punitive, or for economic loss, loss of revenues, loss of profits, loss of business opportunity, or as a result of fines levied by governmental or regulatory authorities or the courts.

16. **Consultant's Manager/Staff: Consultant Not Agent**

(a) Prior to commencing the Work, the Consultant shall appoint a manager or professional as Project Manager who will be responsible for the administration and co-ordination of all phases of the work. All staff of the Consultant employed on the project shall have the knowledge, abilities, experience, and qualifications required for the Work and shall be committed to the Work. The Consultant must provide such additional support as may be required from time to time for the proper performance of the Work, and as may be necessary for completion of the Work within any completion date.

(b) Changes to Consultant personnel and support staff shall require the Purchaser's prior written approval. The Purchaser may request, at its discretion, that the dedicated project individual(s) be changed. The Consultant shall endeavor to accommodate such requests.

(c) The Consultant shall have no authority to bind the Purchaser or to assume or create any obligation or responsibility expressed or implied on the Purchaser's part, or in its name, nor shall it represent to anyone that it has such power or authority, except as expressly provided in this contract.

(d) The Consultant is independent from the Purchaser at all material times. Any subcontractor performing services on behalf of the Consultant shall be deemed to be an "agent or employee" of the Consultant, and under no circumstances be considered to be an agent or employee of the Purchaser.

17. **Assignment or Subcontracting**

Neither party shall assign or subcontract this contract or any portion thereof without the prior written consent of the other; but, notwithstanding the foregoing, the Purchaser may, without the Consultant's consent, assign this contract or any portion thereof to one an affiliate, as "affiliate" is defined under the Ontario *Business Corporations Act*, R.S.O. 1990, c. B.16, as amended.

18. **Offshore Consultants**

The Consultant is responsible for applying to the Government of Canada for admission of personnel into Canada and for obtaining work permits where required. The Consultant will be required to obtain customs clearance and pay duties and taxes where applicable, for goods or tools used in the performance of the Work or imported into Canada. Assistance with clearance of goods will be provided by the Purchaser if requested.

19. **Withholding Tax**

(a) Certain amounts paid or credited to non-residents of Canada are subject to income tax withholding in accordance with rates and conditions set forth in the *Income Tax Act* and tax treaties. This tax is remitted to Canada Revenue Agency (CRA).

(b) For U.S.-based Consultants:

(i) a 15% withholding tax is required on the gross amount payable for services rendered in Canada (e.g. consulting fees, maintenance fees).

(ii) a withholding tax is required on rentals, royalties and similar payments (including payments for the rights to use computer software). The rate is 25% but is generally reduced to 10% under the Canada-U.S. Tax Convention, and is zero in certain circumstances. Where the Consultant either provides representation acceptable to the Purchaser, that it does not carry on or has not carried on business in Canada through a permanent establishment ("p.e.") and that the payments are not effectively connected to such p.e., or alternatively, the Purchaser is provided with a CRA waiver from the withholding requirement, the Purchaser will apply the 10% withholding or zero withholding to the payments, as applicable. In either case, the Consultant must indemnify the Purchaser for any tax, penalties and interest that may be assessed to the Purchaser by the CRA for failure to withhold the required tax (i.e. 25%) from the payments. The Consultant agrees to notify the Purchaser within thirty days of commencing to carry on a business in Canada through a permanent establishment to which the payments due under this contract are effectively connected.

(iii) Each February, the Purchaser issues CRA forms, either a NR4 or T4A-NR (depending upon the nature of the payment made) to all non-resident Consultants who were paid by the Purchaser during the previous year.

(c) Under no circumstances will Purchaser:

(i) make any tax equalization payments of any kind to Consultant; and,

(ii) have any liability for any of the Consultant's income, payroll, or capital (including large corporation) taxes imposed by any governmental authority in connection with this contract.

20. **Equipment Owned by the Purchaser**

(a) Equipment authorized by the Purchaser for purchase by the Consultant or supplied to the Consultant by the Purchaser shall be used solely in the performance of the Work in a manner authorized by this contract; any use of the equipment for any other purpose or manner is strictly prohibited and will constitute an improper use of the Purchaser's equipment. The Consultant acknowledges and agrees that any improper use of the Purchaser's equipment will constitute a breach of the Consultant's duty of good faith and loyalty to the Purchaser, and a breach of this contract. In addition to all other rights and remedies available to the Purchaser, at Purchaser's sole and absolute discretion, improper use of the Purchaser's equipment will be cause for immediate termination of this contract under Section 20 herein. For any improper use of Purchaser's equipment, the Consultant will pay the Purchaser, as liquidated damages and not as a penalty, an amount equal to the greater of (i) five thousand dollars, or (ii) the amount of revenues generated, directly or indirectly which, the improper use of such equipment facilitates. Any damage, loss, or other diminution in value of equipment shall be additional to liquidated damages. Title to such equipment shall remain with the Purchaser. Equipment shall be clearly identified as property of the Purchaser. The Consultant shall be responsible for safeguarding such equipment (including without limitation, safety of Consultant and others from the equipment) while in its custody or control, maintaining a system of inventory control acceptable to the Purchaser. The Purchaser shall have reasonable access to the premises of the Consultant for the purpose of verifying records and auditing inventories of such equipment.

(b) Following completion of the Work or early cancellation or termination of this contract, the Consultant shall, unless otherwise directed, make all such equipment immediately available for pickup by the Purchaser. The Consultant shall be liable for the repair or replacement of all equipment owned by the Purchaser which becomes damaged or lost while in the custody or control of the Consultant. The Consultant shall maintain insurance, in which the Consultant and the Purchaser shall be named jointly as insured, covering the full replacement value of all such equipment against the risk of loss or damage.

21. **Invoicing**

(a) Charges for services rendered and reimbursable expenses incurred may be submitted monthly unless otherwise specified in the purchase order. Invoices shall be in such detail and format as specified from time to time by the Purchaser. Payment of acceptable invoices shall be made 30 days after receipt thereof.

(b) The GST/HST, together with the registration number for same, shall be shown separately on all invoices. The Consultant shall deduct all recoverable GST/HST paid from reimbursable expenses before adding GST/HST to amounts to be invoiced to the Purchaser.

(c) If at any time during the performance of the Work there are deficiencies in the Work, including non-delivery of an acceptable final report, the Purchaser shall have the right to withhold from any invoice an amount that, in the Purchaser's opinion, takes into account the deficiencies. Any amount withheld will be paid 30 days after receipt of invoice submitted after the Purchaser's approval of the correction of deficiencies.

22. **Insurance and WSIB Coverage**

In connection with the performance of any Work pursuant to these terms and conditions, the Consultant covenants and agrees to maintain insurance coverage, as well as registration and coverage under *Workplace Safety and Insurance Act, 1997*, S.O. 1997, as amended ("WSIB Coverage"), in accordance with the terms and limits of the Purchaser's document titled "Insurance Requirements", or in accordance with such other document identified in the purchase order that requires the

Consultant to maintain insurance coverage and WSIB Coverage.

23. **Progress Reports**

The Consultant shall forward to the Purchaser on or before the 20th day of each month, a progress report in such form and detail as may reasonably be requested by the Purchaser, showing the progress of the Work to the end of the preceding month. Such report shall also include a summary of the costs to date, estimated cost to completion of the Work, an explanation of any variance from the original estimate, and shall disclose accurately and clearly any other facts concerning the transaction which the Consultant believes are relevant. The Consultant shall notify the Purchaser immediately upon having expended or committed 80% of the authorized funds.

24. **Completion of the Work**

The Consultant shall complete the Work in a diligent, professional, prudent, and workmanlike manner in accordance with the schedule set forth in this contract and, if necessary, will increase the level of effort/resources necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain schedule.

25. **Contract Cancelation**

(a) The Purchaser shall have the right, which may be exercised at any time, and from time to time, to cancel this contract, or any uncompleted or unperformed portion of the Work or part thereof.

(b) Unless otherwise agreed in writing between the Consultant and the Purchaser, in the event of such cancellation, the Purchaser shall be obligated to pay the Consultant only for reasonable, necessary, unavoidable, and unrecoverable direct costs incurred by Consultant by reason of any undertakings or commitments by Consultant prior to the expiry of the notice period. Such costs are to be supported by audit, if required by Purchaser, performed by auditors acceptable to the Purchaser. The Purchaser will not be liable for any other amounts. The Consultant shall not undertake any forward commitment after receipt of notice of cancellation.

(c) Title to all Work for which reimbursement is made shall vest with the Purchaser. The above payment procedure shall not apply to situations in which the Purchaser is entitled to terminate this contract by reason of default by the Consultant in the performance of its obligations.

(d) The Purchaser shall not be liable to the Consultant for loss of anticipated profit on the cancelled portion or portions of the Work, or any other incidental, indirect or consequential damage.

(e) The Consultant shall not undertake any forward commitment after receipt of notice of cancellation.

(f) The remedies in this Section 25 shall be the Consultant's sole and exclusive remedies for cancellation of this contract.

26. **Suspension of Work**

(a) The Purchaser shall have the right, which may be exercised from time to time without invalidating this contract, to delay the start date or suspend performance by the Consultant of any part or the whole of the Work for such reasonable period of time as the Purchaser may notify the Consultant. Except to the extent any such delay or suspension arises from default by the Consultant, the Purchaser shall pay to the Consultant the pre-approved actual necessary, reasonable, unrecoverable, and unavoidable extra direct expenses incurred by the Consultant arising from the suspension, provided that in no event will the Purchaser be liable to the Consultant for loss of profit, loss of revenues, interest loss, loss of business opportunity, or any other damages or loss occasioned to the Consultant by reason of any such Work suspension. Such extra expenses shall be supported by audit, if required by the Purchaser, carried out by auditors acceptable to the Purchaser, prior to payment of same.

(b) The resumption and completion of the Work after the suspension shall be as established by the parties having regard to the duration of such delay or suspension, and the nature of the Work.

27. Default by Consultant - Termination

(a) Without limitation, the following actions by or circumstances relating to the Consultant shall constitute default on the part of the Consultant:

(i) committing any act of insolvency or bankruptcy, voluntary or otherwise;

(ii) having a receiver appointed on account of insolvency or in respect of any property;

(iii) making a general assignment for the benefit of creditors;

(iv) failing to pay accounts relating to the Work as they come due;

(v) failing to prosecute the Work with skill and diligence;

(vi) assigning or subletting this contract or any portion thereof without the required consent;

(vii) failing or refusing to correct defective or deficient Work;

(viii) being in breach of sub-Section 9(d)

(ix) failing to disclose all material details in respect of an Unfair Advantage during the procurement/bidding stage, or of a Conflict of Interest at any point, or being in breach of Section 10(b) hereof;

(x) being otherwise in default in carrying out any of its obligations under this contract, whether such default is similar or dissimilar in nature to the causes listed previously.

(b) Notice that the Consultant is in default shall not be required if the default relates to the bankruptcy, insolvency or financial instability of the Consultant. Ten days' written notice shall be given in the event of other defaults.

(c) If the Consultant is in default under this contract, then the Purchaser shall be entitled to:

(i) take possession of all of the Work in progress;

(ii) eject and exclude from the Purchaser's premises all personnel of the Consultant and any sub-consultant;

(iii) terminate the Purchaser's utilization of the Consultant to perform the Work;

(iv) finish the Work by whatever means it may deem appropriate under the circumstances;

(v) withhold any further payments to the Consultant until its liability to the Purchaser is ascertained.

(d) The Consultant shall be liable to the Purchaser for:

(i) the extra expense of finishing the Work, including compensation to the Purchaser for additional managerial and administrative services;

(ii) the cost of correcting defects (if any) in that portion of the Work performed by the Consultant; and

(iii) all other loss, damage and expense occasioned to the Purchaser by reason of the Consultant's default.

(e) Any action by the Purchaser under this Section 27 shall be without prejudice to the Purchaser's other rights or remedies under law or under any surety bond or other security held by the Purchaser for performance of this contract by the Consultant.

(f) The Consultant's performance under this contract, whether or not a default has occurred, may impact the Purchaser's assessment of the Consultant to perform future work by the Purchaser or its affiliates.

28. **<u>Qualifications</u>**

(a) The Consultant, the supervisor and employees, representatives and agents, and sub-consultants must be able to demonstrate that he, she or it has Qualified and Competent workers with suitable experience and adequate equipment to carry out the specified work safely. The Consultant shall rectify immediately safety rule violations by its employees and sub consultants. Refusal to do so and or repeated violations will result in permanent removal of the offender from the work or cancellation of this contract. The definitions of Qualified and Competent are as follows:

(i) "Qualified" means a person who is accepted as satisfactory in reference to experience, personal competency, and familiarity with rules, procedures, apparatus, and dangers involved in the work.

(ii) "Competent" means a person who:

A. is qualified because of his or her knowledge, training and experience to organize and perform the work;

B. is familiar with the provisions of the *Occupational Health and Safety Act*, R.S.O. 1990, c.O.1, as amended, and the Purchaser's corporate policies and procedures set forth herein that apply to the work;

C. has the requisite knowledge of any potential or actual danger to health and safety in the workplace;

D. is fit to perform the work, both physically and mentally; and,

E. is at least 18 years of age or such higher age as may be prescribed by law.

29. **<u>Security/Safety Measures</u>**

(a) Site Access

(i) The Consultant may, during the term of this contract, be required to complete and submit to Purchaser, Personnel Risk Assessment Forms as provided in the Request for Proposal Documents, for any and all personnel expected to have access to any of the properties, offices, or confidential or proprietary information of the Purchaser for the purpose of assisting the Consultant to provide any of the said services.

(ii) Once security checks have been successfully completed, the Purchaser will issue letters to the Consultant's representative authorizing site access to each applicant. The Purchaser's letter must be presented prior to access to the Purchaser's sites.

(iii) The aforementioned security requirements shall remain in force during the entire term of this contract. Notwithstanding anything else in this contract:

A. If stated in this contract and/or If so instructed by the Purchaser in writing, the Consultant shall not commence providing the said services prior to the Consultant's receipt of the Purchaser's letters authorizing site access to each applicant. The Purchaser's letter must be presented prior to access to the Purchaser's sites;

B. if the security status changes of any personnel, employee or subcontractor employee during the term of this contract, the Consultant shall not continue providing the said services utilizing the employee or subcontractor employee until such time as the Consultant receives from the Purchaser a letter authorizing site access based on said changed security status. In such an event, the Consultant shall diligently endeavour to complete the Work in accordance with the schedule set forth in this contract and, if necessary, will increase the level of effort necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain schedule. The Purchaser may in its sole discretion and without any cost to the Purchaser refuse access to the Purchaser's properties, offices, or confidential or proprietary information to any any worker (Consultant personnel, employee or subcontractor employee) with a criminal record. If the Purchaser does not refuse access to the Project Site to any such worker with a criminal record, the Consultant will not be relieved of any of its obligations under this contract respecting that worker and the Consultant will remain completely responsible for all actions and failures to act of all workers of the Consultant and any subcontractors while at the Project Site; and,

C. in addition to any other remedy that the Purchaser may have against the Consultant as a result of the Consultant's failure to comply with all the terms of this Section, the Consultant shall, to the extent that delay in providing the said services occurs as a result of the non-delivery of signed and witnessed Personnel Risk Assessment, Authorization and Release forms as required by (i) and (ii), be liable to the Purchaser for all damages arising out of the said delay.

(b) Security

(i) The Consultant shall protect Purchaser Property and computer resources against damage and waste including, without limitation, following all rules established for protection against computer viruses.

(ii) The Purchaser retains the right to terminate for cause this contract or stop the Work at any time should the Purchaser in its sole discretion determine that any Consultant Staff Member is a security risk and/or the information provided in the Personnel Risk Assessment form or any other security related documentation was misleading or incorrect.

(iii) The Consultant shall obey all rules and regulations established by the Purchaser regarding the premises to which the Consultant has access and projects on which the Consultant performs the Work.

30. **Indemnification**

The Consultant shall indemnify and hold harmless the Purchaser and its agents, employees, directors, officers, shareholders, partners and affiliates, from and against all claims, demands, losses, costs, expenses (including, but not limited to court costs, legal fees and disbursements) damages, actions, suits, proceedings, or fines (imposed by third parties, including, without limitation, the provincial or federal governments or the courts thereof or any governmental agencies), that arise out of or result from or are attributable to the Consultant's performance of this contract (hereinafter called "claims") or relating to environmental, health or safety hazard(s) or condition(s) to the extent that such claims are caused by breach of contract or negligent or wilful acts or omissions of the Consultant, any sub consultant and anyone directly or indirectly employed by any of them or anyone for whose acts any of them may be liable. The said indemnification shall apply whether the claims are in tort or in contract and whether the claims are for direct damages, indirect damages, punitive damages, economic loss, loss of revenues, loss of profits, or as a result of fines.

31. **Interpretation of Contract Liability**

If at any time there is more than one legal entity constituting the Consultant, their covenants under this contract shall be considered to be joint and several and apply to each and every entity. If the Consultant is or becomes a partnership or joint venture, each legal entity who is a member or becomes a member of the partnership or joint venture or its successors is and continues to be jointly and severally liable for the performance of the services and all the covenants of the Consultant pursuant to this contract whether or not that entity ceases to be a member of the partnership, joint venture or its successor.

32. **Notices**

(a) Notices to the Purchaser shall be addressed to the General Counsel, Hydro One Inc., 483 Bay Street, 15th Floor, North Tower, Toronto, Ontario M5G 2P5. Such notices shall be effective upon receipt.

(b) Notices to the Consultant shall be effective upon delivery to the Consultant or the sending of same by registered post to the Consultant's last address recorded with the Purchaser.

33. **Re-employment of Former Employees**

(a) The Purchaser has a policy restricting the involvement, in the Purchaser's contracts, of former employees of Ontario Hydro or Hydro One Inc. or its subsidiaries that left those corporations under various staff reduction programs from 1992 onward. These restriction apply when (a) such former employee(s) owns 10% or more of the shares of a company, or (b) such former employee(s) perform the contracted service, regardless of the manner of contracting (whether as an employee, consultant, contractor or otherwise).

(b) Accordingly, where 10% or more of a company is owned by such former employee(s), or where it is anticipated that such former employee(s) will be utilized in the performance of this contract, the Consultant shall identify the individual(s) involved and the details of their ownership or employment with the Consultant. The Consultant represents and warrants that this disclosure was correctly made in its Proposal or response to the Purchaser, and that the same is true as of the date of entering into this contract. This disclosure shall remain a continuing disclosure obligation of the Consultant during the performance of this contract.

34. **Interpretation of Contract and Disputes**

(a) This contract shall be governed by and interpreted in accordance with the laws of the Province of Ontario.

(b) The parties irrevocably submit to the exclusive jurisdiction of the courts of Ontario and the

Federal Court of Canada. All disputes in connection with this contract shall be commenced and heard in a court of competent jurisdiction in Toronto, Ontario.

35. **<u>Laws, Regulations, and Codes</u>**

The Consultant shall comply with all federal, provincial, and municipal statutes, regulations, bylaws, standards, and codes which are applicable to the Work.

End of A-29-2010 Document

Statement of Work
for the
Dx Total Factor Productivity (TFP) Study
RFP Number 7000005911

PSE POWER SYSTEM ENGINEERING

hydro one

[MMMM DD, YYYYY]

Document History			
Version	State / Changes	Date	Author

1 Hydro One – Dx TFP Study Project

This document provides an overview of the tasks to be completed by Power System Engineering, Inc. (PSE) in the Scope of Work (SOW) for the successful completion of the Dx TFP Study project.

Power System Engineering, Inc. (PSE) proposes to measure and evaluate Hydro One's total factor productivity (TFP). The study is in accordance with the directive of the Ontario Energy Board found in the Board's March 12, 2015 Decision to EB-2013-0416. The Board states on page 17 of the Decision,

> "The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB requires Hydro One to conduct such a study. Given Hydro One's concerns, the OEB leaves it to Hydro One to determine its preferred total factor productivity study method. However, the period of the study should include years at least going back to 2002. The results of the study must be filed as part of Hydro One's next rates application."

PSE's TFP study will satisfy this Board directive and provide the Board with an accurate assessment of Hydro One's own TFP trend.

PSE is well-positioned for this study. We have conducted numerous TFP and efficiency studies for other distribution electric utilities. PSE is also well-versed in presenting TFP and efficiency results to stakeholders in Ontario. Our prior experience working with the CLD during the 4th Generation Incentive Regulation proceeding when the OEB efficiency and TFP assessments were developed will enable PSE to "hit the ground running" on this project.

2 Scope of Work for Dx Total Factor Productivity (TFP) Study

2.1 Scope of Work Description

The scope of work is to conduct an electric distribution TFP study that involves an accurate evaluation of Hydro One's own TFP trend from 2002 to 2022.

PSE will re-do the TFP trend calculations to make them more comprehensive than the calculations performed by Pacific Economics Group (PEG). Currently the "outputs" included in PEG's TFP calculations do not include important outputs, such as service quality, reliability, and regulatory and environmental efforts. Incorporating these outputs will enable the TFP calculation to encompass more relevant and measurable outputs, which in turn will allow us to measure Hydro One's TFP trend in a more accurate and fair manner.

During the study, PSE will have interim progress reports and provide summary updates on the research whenever requested. While we present high-level steps below, our project plan remains flexible and based on the needs of Hydro One. PSE will conduct this research as follows (this is subject to modification based on Hydro One directives and stakeholder session outcomes):

1. Project kick-off phone conference
2. Prepare a draft study proposal for review by Hydro One.
3. Present and explain the proposed TFP study framework and methodology at a stakeholder session.
4. Meet with Hydro One to review suggested changes resulting from the stakeholder consultation.
5. Information and data requests to Hydro One requesting the identification of all possible additional “outputs” impacting TFP and historical and future data elements.
6. Hydro One completes information and data request.
7. Determine list of variables with Hydro One and PSE engineering experts that are theoretically plausible and available for data processing.
8. Gather and process cost, output, and potential service territory variables for an econometric model that may provide weights for the TFP outputs.
9. Estimate econometric model that quantifies the weights for possible outputs.
10. Determine comprehensive “outputs” for Hydro One TFP.
11. Determine appropriate weights for the TFP outputs to be included in the Hydro One TFP study.
12. Calculate Hydro One TFP trend from 2002-2022 (2015-2022 results will only be available once projected data is provided to PSE).
13. Prepare draft TFP study and preliminary study results.
14. Receive feedback from Hydro One.
15. Present a final TFP study.
16. Status update calls.
17. Defend the study during Part B of the project based on the requests of Hydro One.

3 Project Execution Approach

The project execution approach is flexible and will be customized to meet the needs of Hydro One. PSE suggests a kick-off call introducing PSE team members to Hydro One team members. The project manager, Mr. Fenrick of PSE, will also be the liaison between PSE and Hydro One. We recommend that Hydro One designate a contact person for the project as well. All data requests, data submissions, scheduling, and other communications should then be coordinated between the Mr. Fenrick and the Hydro One contact person(s).

PSE will provide project updates to Hydro One regularly, as project milestones approach and whenever requested by Hydro One. Project progress will be tracked and monitored to assure key project timelines are met.

4 Assumptions

The following are assumptions are assumed within this project proposal. They are:

- Stakeholder feedback, including that of Hydro One, will not significantly modify the overall scope of the project. The fixed price quote assumes the final project design will be similar to the proposed design in this SOW.

5 Project Schedule

Please refer to next page.

Anticipated Project Timeline

Aug-15 | Sep-15 | Oct-15 | Nov-15 | Dec-15 | Jan-16 | Feb-16 | Mar-16 | Apr-16 | May-16 | Jun-16 | Jul-16 | Aug-16 | Sep-16 | Oct-16

	Task
1	Kick-off call with PSE/Hydro One
2	Develop Study Plan
3	Present Study Plan to stakeholders
4	Meeting between PSE and Hydro One
5	Information and Data request to Hydro One
6	Hydro One fills out data request
7	Determine list of variables that are theoretically plausible and available for data processing
8	Gather and process North American cost, outputs, and explanatory variable data
9	Estimate cost driver model
10	Determine comprehensive "outputs" for Hydro One TFP
11	Develop appropriate "weights" for comprehensive outputs for TFP
12	Calculate Hydro One TFP trend from 2002-2022
13	Prepare draft TFP study and preliminary study results
14	Receive feedback from Hydro One
15	Present final TFP study to Hydro One
16	Status update calls (PSE is always available to provide status update when requested)
17	Participate in the defense of the TFP Study (Part B) — 2017 as requested

PSE Task

Hydro One Task

Joint Task

PART 3: TERMS OF REFERENCE

1.0 Background

Hydro One Inc. is a holding company with subsidiaries that operate in the business areas of electricity, Transmission and Distribution ("T&D"), and telecom services. Hydro One Inc. is wholly owned by the Province of Ontario and our T&D businesses are regulated by the Ontario Energy Board ("OEB"). Our industry, including our company, is governed within the broad legislative framework of the Electricity Act and the OEB Act.

Hydro One Networks Inc. ("Hydro One") represents the majority of Hydro One Inc. business. As stewards of the Province's electricity grid, our core role is to provide safe, reliable and cost-effective electricity transmission and distribution and to connect clean and renewable sources of generation to the province's electricity grid.

Hydro One Telecom Inc. is a CRTC-registered, non-dominant, facilities-based carrier involved in marketing the excess fibre-optic capacity. We provide broadband telecommunications services in Ontario with connections to Montreal, Buffalo, and Detroit. Building on the expertise and reliability of Hydro One, Hydro One Telecom delivers broadband telecommunications solutions for Carriers, ISP's, commercial customers and the Public Sector.

Hydro One is the largest electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 96.6% of Ontario's transmission capacity based on the revenue approved by the OEB. Based on assets, our transmission system is one of the largest in North America and our distribution system is the largest in Ontario.

The following link can be found and accessed in Part 5 - Attachments and Hyperlinks. In this website, information about Hydro One Inc. and its subsidiaries is available.
Website: http://www.hydroone.com/OurCompany/Pages/QuickFacts.aspx

2.0 Hydro One Distribution Total Factor Productivity (TFP) Study

2.1 Distribution TFP Study Framework

In the OEB Decision regarding Hydro One Distribution Rates (EB-2013-0416) dated March 12, 2015, the OEB directed Hydro One to perform a TFP study of Hydro One's own productivity. The OEB saw value in Hydro One measuring its own TFP over time to be able to demonstrate improvement in productivity to its customers and the OEB. Hydro One is to determine its preferred TFP study method and include years back to 2002. The results are to be submitted with Hydro One's next distribution rate application which will occur in the first quarter of 2017.

A link to the Hydro One Distribution Rate Decision can be found at this link:

http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Dec_Hydro%20One%20DX_20150312.PDF

2.2 Deliverables

Hydro One is undertaking a Distribution TFP study with the expectations that the successful proponent will;

- Demonstrate expertise and knowledge of TFP Studies by recommending a methodology/framework that best suits Hydro One Distribution and considers business circumstances and other material factors;
- Explain why such methodology/framework is recommended over other possible alternatives;
- Recommend which cost drivers are relevant, measurable and will garner the appropriate reliable results through the Study;
- Identify and explain any normalization or other adjustments made to data used in the TFP calculations;
- Describe how the recommended model accounts for fluctuations in business circumstances such as load and demand, changes in external economic factors and amendments in industry policy/regulation over time;
- Illustrate how the recommended TFP methodology is consistent with the requirements of the OEB's Renewed Regulatory Framework for Electricity Distributors[1];
- Perform a year-over-year TFP trend analysis for Hydro One Distribution from 2002 and project results up to 2022;
- Make specific recommendations on how to improve Hydro One Distribution's TFP performance; and
- Clearly identify and explain the inputs and parameters used in the TFP study.

3.0 SCOPE OF WORK

3.1 Project Requirements

Part A

1. Design and complete a repeatable TFP study for Hydro One's distribution business which contains the elements in section 2.2 above and includes:

    - A description of the methodology/framework to be used to complete the study to meet Hydro One's expectations;
    - Findings and conclusions on the reasonableness of Hydro One's TFP; and

[1] On October 18, 2012, the Ontario Energy Board released its Report, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE).

- A summary report on business performance and recommend measures that could be utilized by Hydro One.

2. Prepare a draft study proposal for review by Hydro One on or before beginning of August 2015.
3. Present and explain the proposed TFP study framework and methodology at a stakeholder session with the objective of gaining endorsement of the process and input on the same. Hydro One will retain the right to unilaterally decide any questions related to the study. A stakeholder session will include a one hour to two hour preparatory meeting with Hydro One and will be up to three hours in duration.
4. Meet with Hydro One to review suggested changes resulting from the stakeholder consultation.
5. Provide interim progress reports as requested by Hydro One.
6. Provide draft TFP study and preliminary study results by August 2016.
7. Present a final TFP study to Hydro One by October 2016 for submission to the OEB.

Part B

8. Participate fully, in cooperation with Hydro One, in the filing, discovery, hearing and argument phases of the Hydro One distribution rate application process as they pertain to the TFP study.
9. Defend the TFP study framework, methodology, findings and conclusions in the Hydro One distribution rates application proceeding in the normal phases of the regulatory application process as defined by the OEB. This includes the preparation of other related evidence as necessary to support the TFP study and expert witness testimony.

3.2 Consultant Requirements

The consultant required for this assignment must:

- Be able to provide all of the services outlined in Section 3.0;
- Have expertise and proven experience in preparing a TFP study and defending recommendations in a regulatory environment;
- Have in-depth knowledge and experience in applying general regulatory principles as they apply to the project scope;
- Have knowledge of specific practices and precedents within the regulated utility industry;
- Have significant experience in acting as an expert witness at rate hearings in the subject areas covered by this work scope;
- Be able to demonstrate that they have successfully completed similar work for other large clients, on time and on budget;

3.3 Schedule

The schedule for completion of the activities is driven for by regulatory requirements for a new rate application to be submitted in the first quartile of 2017. The consultant shall base their response to this RFP on meeting the following schedule of major milestones:

1. Deliver the Draft Study Proposal	August 2015
2. Stakeholder Consultation Presentation	September 2015
3. Deliver the Draft Report	August 2016
4. Deliver the Final Report	October 2016
5. Fully participate in the regulatory proceedings	As required

3.4 Pricing

For Part A

Preparation of the study and report outlined in Part A should be costed and a single lump sum price is to be provided for <u>each</u> study.

For Part B

Please provide individual hourly rates, as appropriate. Expected reimbursable expenses must be pre-approved and in accordance with the Ontario Public Service Travel, Meal & Hospitality Expense Directive.

School Energy Coalition Interrogatory # 11

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 5

Interrogatory:

Please describe the extent, if any, that the willingness of the regulator to allow larger regulated rate increases has an impact on spending and therefore TFP.

Response:

To the extent that larger rate increases lead to increased spending amounts, these increases will result in a lower TFP trend.

School Energy Coalition Interrogatory # 12

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 9

Interrogatory:

Please comment on whether, given the positive 0.5% TFP of the Hydro One over the last few years, it would be possible or appropriate for the Board to use a 0.5% productivity factor to signal to the Hydro One its need to bring its benchmarking results in line with the expected costs over time.

Response:

This would not be appropriate and would violate well-established incentive regulation principles. Deriving the productivity factor from a utility's own TFP will substantially weaken incentives to increase TFP for future years. Penalizing Hydro One for their positive TFP trend would not be the proper signal to send to Hydro One.

School Energy Coalition Interrogatory # 13

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
A-03-02-01 Page: 9 and 13

Interrogatory:
Please provide any data in the possession of the consultant showing the impact on TFP of "the aging of capital infrastructure".

Response:
Please refer to Exhibit I-8-Staff-032.

School Energy Coalition Interrogatory # 14

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 9 and 22

Interrogatory:

Please confirm that the primary reason for the Hydro One's positive TFP from 2010-2015 is its control of OM&A costs relative to inflation. Please quantify if possible the impact of this factor on the TFP trajectory for this period

Response:

The lower growth in OM&A relative to inflation contributed to the positive TFP by approximately 0.5%. If the OM&A expenses had increased by the OM&A input price inflation rate from 2010 to 2015, then the adjusted TFP becomes 0.0%.

School Energy Coalition Interrogatory # 15

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 24

Interrogatory:

Please provide an estimate of the quantitative difference between using Handy-Whitman and using EUCPI for this TFP study.

Response:

For the full 2002-2015 period, the Hydro One TFP trend would decrease by approximately 0.9% if the EUCPI were used rather than the Handy-Whitman index. Please see pages 24 and 25 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, for an explanation of the rationale for using the Handy-Whitman index rather than the EUCPI.

School Energy Coalition Interrogatory # 16

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 26

Interrogatory:

Please confirm that the figure of 1.8% increase in the capital quantity index is incremental to the figure of 2.6% increase in the capital price.

Response:

PSE does not understand the question. If it is asking if the capital quantity index growth rate is derived from subtracting the capital price growth rate from the capital cost growth rate, then we can confirm that.

School Energy Coalition Interrogatory # 17

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 27 and 41

Interrogatory:

Please compare the TFP results for Hydro One on p. 27 to the results for the industry on p. 41, and describe the primary reasons why the results are different.

Response:

The biggest reason for the difference is that the two TFP results are measuring different metrics. The Hydro One TFP results are measuring Hydro One's own TFP trends, as directed by the Board. The industry TFP trend results include all Ontario distributors except Toronto Hydro and Hydro One. This means the two TFP trends are calculated using entirely different data.

A second reason for the difference is the use of the Handy-Whitman index for the Hydro One TFP trend, compared to the use of the EUCPI for the Ontario industry TFP trend. The Handy-Whitman index is used for Hydro One because it is a far better measure of capital asset costs compared to the EUCPI. Handy-Whitman is better because the EUCPI:

1. Likely includes financing costs;
2. Is not specific to the distribution industry; and
3. Was discontinued in 2014.

Conversely, the Handy-Whitman index does not include financing costs, is specific to the distribution industry, and continues to be updated every six months. In reading the Board's directive in EB-2013-0416 the Board states: "The OEB leaves it to Hydro One to determine its preferred total factor productivity study method." This statement was in the context of Hydro One measuring its own TFP trend over time.

PSE did not endeavor to modify the asset price assumption when updating the 4GIR research. We only modified those aspects of the method that could not be exactly replicated. Please see Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric

Distribution Functions of Hydro One and the Ontario Industry, Section 2.1.3, pages 8 and 9, where we discuss how the Hydro One and Ontario TFPs should not be used for comparative purposes.

School Energy Coalition Interrogatory # 18

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
A-03-02-01 Page: 34

Interrogatory:
Please confirm that Table 15 means that 38.5% of the inputs of the adjusted TFP model are assumed to be used to deliver reliability outputs. If this is not correct, please describe more fully the quantitative impact of the reliability weights on the resulting TFP.

Response:
Confirmed.

School Energy Coalition Interrogatory # 19

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 42

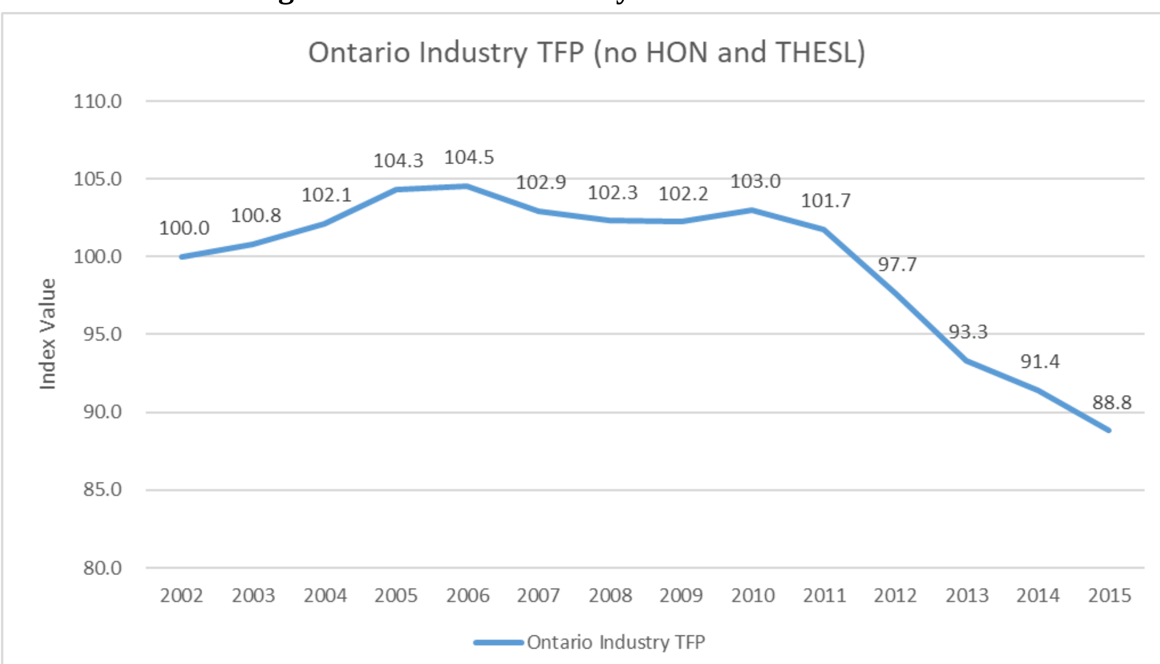
Interrogatory:

Please confirm that it is correct to read this table as demonstrating that Ontario industry TFP (excluding Toronto Hydro and Hydro One) has declined by 11.3% from 2010 to 2014. Please provide the 2015 and 2016 figures for this Figure 7.

Response:

Confirmed, assuming the 11.3% is calculated arithmetically. The decline is 11.9% if measured logarithmically. PSE did not update the study to 2016 in our research. Figure 7 updated through 2015 is provided below.

Figure 7 – Ontario Industry Historical TFP



School Energy Coalition Interrogatory # 20

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
A-03-02-02

Interrogatory:
With respect to the retainer of Power System Engineering to carry out the benchmarking study:

a) Please provide the agreement between the Hydro One and the consultant, including all amendments.

b) Please provide the scope of work or other documents describing the initial instructions to the consultant, if they are not included in (a).

c) Please provide all written instructions to the consultant by the Hydro One or by counsel or others on other behalf, including but not limited to suggestions for edits to early drafts.

Response:
a) Please refer to Exhibit I-10-SEC-020, attachments.

b) Please refer to a) above.

c) In order to prepare its independent benchmarking study, Power System Engineering met regularly with Hydro One staff. Discussions included detailed aspects of the TFP and benchmarking studies. Throughout this process, Hydro One was afforded the opportunity to discuss and clarify preliminary observations made by Power System Engineering. These discussions and commentary occurred over a number of months, took several formats (oral discussions, emails and telephone meetings). Hydro One had no decision-making role regarding the content or the conclusions that were reached by Power System Engineering. The underlying information that Power System Engineering has relied on for purposes of its reports is not a matter within Hydro One's domain or control. The requested compilation of all correspondence, exchanges, discussions that took place between Hydro One employees and Power System Engineering would take an inordinate effort and cost without any real or apparent purpose to the Board's consideration and review of the issues in this proceeding. Hydro One therefore declines to provide the requested information.

Neither Hydro One nor its counsel provided any instructions to Power System Engineering that would in any way impair or affect the objectivity and independence of the author's stated conclusions and findings. If SEC wishes to test the objectivity and independence of Power System Engineering and the conclusions that they have reached, this can occur through questions asked to Power System Engineering witnesses, and the testing of whether, or not, Power System Engineering's independence and objectivity was at any time impaired by the process which Power System Engineering used to prepare its reports.

VENDOR ACCEPTANCE FORM

Purchase Order number: 4500521667 Version: 0
To: POWER SYSTEM ENGINEERING INC
Attn:
FAX: 608-22-9378
Number of Pages: 8 - Including Cover Page

Return to Purchaser's Contact: Hydro One Networks Inc
Attn: LYNNETTE HARRIS
483 Bay Street, 6th Floor,
Toronto, Ontario M5G 2P5
Canada
Fax: 416-345-6068
Email: LYNNETTE.HARRIS@HYDROONE.COM

IMPORTANT NOTICE - PLEASE READ!

Immediately upon receipt of the Outline Agreement, Purchase Order Release, Purchase Order or Instruction Notice attached herein, review, duly sign and date this Vendor Acceptance Form and return it via fax or e-mail to the Purchaser's Contact.

Whether or not this Vendor Acceptance Form is signed by the Company, Contractor or Consultant (each, a "Vendor") and returned to the Purchaser's Contact, commencement of work, or supply of goods or equipment, full, partial, or progress payment made by the Purchaser after receipt of acceptable invoice from the Vendor or delivery of the goods or equipment by Vendor shall constitute absolute acceptance of the terms herein set forth or referenced herein. Acceptance may be only on the exact terms herein set forth or referenced herein. No condition stated by Vendor in accepting this offer shall be binding on Purchaser if different from or in addition to the conditions set forth or referenced herein, unless agreed to in writing by Purchaser's Contact by the issuance of a formal Instruction Notice/Change Order.

Vendor Name ____________________________________

By:

____
Vendor Signature / Vendor Signing Authority

Print Name of Person Signing ____

Title: _____________________________________

Date: _____________________________________

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PROPRIETARY

Vendor:
POWER SYSTEM ENGINEERING INC
1532 W BROADWAY
MADISON WI 53713
USA
Attention:
Fax: 608-22-9378

Purchase order

PO Number:	4500521667
Version:	0
Release Date:	11/07/2016
Contract Number:	
Contact:	LYNNETTE HARRIS
Telephone:	416-345-5481
Fax:	416-345-6068
E-mail:	LYNNETTE.HARRIS@HYDROONE.COM
Company Name:	HYDRO ONE NETWORKS INC.

Please deliver to:
Hydro One Networks
99 Caplan Ave
BARRIE ON L4N 9J3
CANADA

Bill to address:
Hydro One Accounts Payable
P.O. Box 4500
Concord ON L4K 5E2

Valid from: 11/07/2016 Valid to: 05/06/2018

Incoterms: FOB PLANT
Terms of payment: within 45 days Due net in Currency CAD
PURCHASE ORDER (PO)

DEFINITION OF TERMS;

"Purchaser" - the corporation (either Hydro One Inc. or one of its subsidiary corporations) designated as the Purchaser in this Purchase Order;

"RFx" - the documents issued by the Purchaser calling for tenders, quotations, responses, or proposals for the supply of the Equipment or for the prequalification to supply the Equipment as further stated in the said document;

"Terms of Payment" - the terms under which the Purchaser will pay the Contract price provided that the Vendor is carrying out its obligations;

"Purchase Order" # a detailed document authorizing a Vendor to furnish goods to a Purchaser;

"Contract" - the Contract establishes the legal relationship between Hydro One and the Vendor and contains the terms and conditions;

"Contract Standard" # a Contract Standard is considered Hydro One's "Standard Commercial Condition" and/or Terms and Conditions for the requirement. The Contract Standard establishes the legal relationship between Hydro One and the Vendor;

"Purchaser's Contact" # the purchasing individual or buyer who is representing the Purchaser and is identified as the contact for this requirement;

"Vendor Acceptance Form" # a form that is sent together with the Purchase Order that the Vendor is required to duly sign and return it via fax or electronically to the buyer immediately upon receipt of the Purchase Order;

"Instruction Notice" # means a document issued by the Purchaser to amend the Purchase Order and agreed to by the Company through its acknowledgement;

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"Contractor" # the person, firm or corporation to whom the Purchaser has awarded the Contract;

"Subcontractor" - a person, firm or corporation having a Contract with the Company for any part of the Equipment;

"Project Site" - the land or actual place designated by the Purchaser for the performance of the work;

"Services" # the labour, effort and/or work that is required by the Purchaser as described in the Purchaser's RFx documents;

"Bidder" - the company making a submission in response to the Purchaser's RFx documents. The Bidder may also be referred to in the Contract documents as the Company, Contractor, Tenderer or Vendor.

"Equipment" # the required materials, machinery, assemblies, instruments, devices, items or articles, as the case may be, or components thereof, required by the Purchaser as described in the Purchaser's RFx documents.

"Vendor" # the successful Bidder who submitted a response to the Purchaser's RFx documents. The Vendor may also be referred to in the Contract documents as the Contractor, Company, Tenderer or Bidder.

"Consultant" # means the individual, partnership or corporation who has been retained by the Purchaser to provide consulting and/or professional services;

This e-mail transmission will serve as the Purchase Order. If you require any assistance please contact the Purchaser's Contact.

PURCHASER'S CONTACT
Purchaser's Contact - Lynnette Harris
E-mail at: lynnette.harris@HydroOne.com
Phone: #416-345-5481
Or by mail:

Hydro One Networks Inc.
Attn: Lynnette Harris
483 Bay Street, 6th Floor, South Tower,
Toronto, Ontario M5G 2P5

DESCRIPTION OF THE WORK: Total Cost Benchmarking Empirical Analysis.

AWARDED TO: PSE (Power System Engineering Inc.)
ATTN: Steve Fenwick

CONTRACT DOCUMENTS AND ORDER OF PRECEDENCE

All in accordance with:
(1) This Purchase Order ("Purchase Order" or "PO") including Vendor Acceptance Form attached herein;
(2) Insurance Requirements
(3) Single Source Contract, A-29-2011 (October 2011) # Contract Standards with Special TC's
(4) Terms of Reference # Total Cost Benchmarking Empirical Analysis

PROPRIETARY

Vendor:
POWER SYSTEM ENGINEERING INC

Purchase order

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These Contract documents shall, to the extent of any inconsistency or conflict, take precedence in the order in which they are named.

Appendices and addenda to any Contract document shall be considered part of such document. The Contract documents form this Contract.

This Purchase Order is subject to amendments in the form of Instruction Notices which shall take precedence over the documents amended thereby.

The decision to proceed with any subsequent phase(s) of the Work will be at the Purchaser's sole discretion. The Purchaser reserves the right to award any subsequent phase(s) of the Work to any other company other than the Consultant.

Any changes affecting the scope, price, source of supply or any terms and conditions of this Purchase Order will be contractually binding only when issued by the Purchaser, by way of an Instruction Notice.

THE PROJECT MANAGER

All reports and documentation relative to the Work shall be addressed to:

Name: LEE Lisa(Seung-Yoon)
Telephone: 416 345-5866

E-mail: lisa.lee@HydroOne.com

Hydro One Networks Inc.
483 Bay St. 7th Floor, North Tower
Toronto, Ontario
M5G 2P5

DURATION/WORK SCHEDULE (CONTRACT TERM)

Work on the Total Cost Benchmarking Empirical Analysis shall begin ASAP, and continue on for an estimated 18 months, or until complete. Complete details and timelines are outlined in the Terms of Reference.

The Consultant shall complete the Work within the timelines dictated by the Purchaser, including final reports and presentations. The Purchaser reserves the right to extend the Contract term.

PRICING SUMMARY

Total professional fees for Part A work (only) is [redacted] outlined in the Terms of Reference is an upset maximum (not to exceed). Actual fees are to be substantiated at time of invoicing and in no event shall they exceed the upset maximum. GST/HST is applicable and QST (if applicable) is extra. The upset maximum does not include GST/HST or QST.

Charge-out rates are as follows (Note: Charge-out rates do not include GST/HST or QST):

Price includes:
- All labour, work equipment, materials and special materials necessary to perform the Services.
- All applicable freight, insurance, WSIB/workers' compensation and all other charges of every kind attributable to the work.

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Reimbursable out-of-pocket expenses are extra and shall be shown separately on the invoices and must be submitted at cost (no mark-up) substantiated with receipts at time of invoicing. All reimbursable expenses require the Purchaser's approval prior to being incurred. All GST/HST and QST paid on reimbursable expenses that is recoverable by Consultant must be deducted from the amount of the expense to be claimed for reimbursement from Hydro One.

Under no circumstances will any expenses be recoverable by the Consultant from the Purchaser, either directly or indirectly, for any hospitality, incidental, or food or beverage expenses incurred by Consultant personnel, or anyone acting on behalf of Consultant, including but not limited to expense in respect of:

(a) meals, snacks and beverages;
(b) gratuities;
(c) laundry, dry cleaning and valet services;
(d) dependant care; and,
(e) personal telephone calls.

Pricing/rates are in U.S. dollars and are not subject to adjustment. Pricing/rates are firm for the duration of the Purchase Order.

TERMS OF PAYMENT

The Terms of Payment are in accordance with Contract Standard A-29-2011 (October 2011).

Payment will be made 45 days after receipt of an acceptable invoice after receipt and acceptance of the Material and or Equipment.

Withholding Tax
(a) Certain amounts paid or credited to non-residents of Canada are subject to income tax withholding in accordance with rates and conditions set forth in the Income Tax Act and tax treaties. This tax is remitted to Canada Revenue Agency (CRA).
(b) For U.S.-based Consultants:
(i) a 15% withholding tax is required on the gross amount payable for Services rendered in Canada (e.g. consulting fees, maintenance fees).
(ii) a withholding tax is required on rentals, royalties and similar payments (including payments for the rights to use computer software). The rate is 25% but is generally reduced to 10% under the Canada-U.S. Tax Convention, and is zero in certain circumstances. Where the Consultant either provides representation acceptable to the Purchaser, that it does not carry on or has not carried on business in Canada through a permanent establishment ("p.e.") and that the payments are not effectively connected to such p.e., or alternatively, the Purchaser is provided with a CRA waiver from the withholding requirement, the Purchaser will apply the 10% withholding or zero withholding to the payments, as applicable. In either case, the Consultant must indemnify the Purchaser for any tax, penalties and interest that may be assessed to the Purchaser by the CRA for failure to withhold the required tax (i.e. 25%) from the payments. The Consultant agrees to notify the Purchaser within thirty days of commencing to carry on a business in Canada through a permanent establishment to which the payments due under this Contract are effectively connected.
(iii) each February, the Purchaser issues CRA forms, either a NR4 or T4A-NR (depending upon the nature of the payment made) to all non-resident Consultants who were paid by the Purchaser during the previous year.

INVOICING INSTRUCTIONS

Hydro One has implemented a supplier portal, powered by Taulia, to save suppliers time, reduce errors, and streamline suppliers' business process when submitting invoices. This easy-to-use online platform provides complete visibility into suppliers' Purchase Order(s), invoices and payment details.

All Hydro One suppliers will be expected to adopt and use the Taulia Supplier Portal for:

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PO Status
Invoice Submission
Invoice Status
Questions related to PO, Invoice, and Payment Details

If you are already enrolled on the Taulia Supplier Portal as a supplier please submit your invoices via the Taulia Supplier Portal at http://portal.taulia.com, using your company ID and Password, do not submit a paper copy invoice through the address below.

If you are not currently enrolled on the Taulia Supplier Portal you can obtain information about the program at http://supplier.taulia.com/customers/hydroone/. This site contains contact information as well as details on the benefits, how to get enrolled and frequently asked questions.

In the short term traditional paper invoices will continue to be accepted; however the Taulia Supplier Portal / E-invoice process will soon be the only method Hydro One will use to receive and process supplier invoices.

Submit original invoices to:

HYDRO ONE NETWORKS INC.NETWORKS INC.
P.O. BOX 4500
CONCORD, ONTARIO
L4K 5E2
ATTENTION: ACCOUNTS PAYABLE

ACCOUNTS PAYABLE INQUIRY:
Telephone Toll Free: 1-800-352-9297
Telephone Local: 416-345-4146
Website: http://www.onlineservice.hydroonenetworks.com/vss/welcome.html

Forward copies of Invoices (including all supporting documentation) to the Project Manager stipulated above.

Payment will be made from an ORIGINAL invoice only. Fax copies will not be processed. Statements can be accepted only with original invoices attached.

IMPORTANT:

The following is mandatory:

Invoices MUST be submitted in accordance with the Contract documents' Terms of Payment and Invoicing requirements and in a format corresponding to the items listed on the face of this Purchase Order. Invoices MUST match the Purchase Order in price and quantity.

All invoices must clearly show:

- Invoice number and date;
- Consultant's name, address, phone number and contact name;
- 'Remit' address, if different than mailing address;
- This Purchase Order number and Purchase Order line number(s) including location of the Work and a short description of the Work the charges relate

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to;
- Quantity 1 lot price;
- Service master number, if provided;
- Applicable tax treatment must be shown separately;
- Where GST/HST/QST is billed, the registration tax number(s) must be noted on the invoice;
- The Purchaser's Project Manager/site contact name;
- Reimbursable expenses (if applicable) shall be shown separately on all invoices and be substantiated with receipts at time of invoicing. All GST/HST and QST paid on reimbursable expenses that is recoverable by Consultant must be deducted from the amount of the expense to be claimed for reimbursement from Hydro One;
- Currency (if not Canadian dollars);
- Terms of Payment as per the Purchase Order;
- Invoices shall detail the hours by individual, their charge out rates, expenses (if applicable) and the Work that the fees relate to.

NOTE:

1. Invoices not conforming to the above instructions/format will be returned to the Consultant.
2. Payments will be made to the "Remittance" address only. Cheques may not be picked up.
3. Do not include charges from more than one Purchase Order on an invoice.

INSURANCE COVERAGE INCLUDING WORKPLACE SAFETY INSURANCE BOARD

If the required insurance coverage expires during the Contract term the Consultant shall ensure that replacement insurance coverage as required in the Contract documents shall be in place immediately so that coverage shall be continuously maintained; and the Consultant shall provide a renewal certificate to the Purchaser's Contact within 14 days of expiration evidencing continued compliance with all terms of the Contract documents.

WORK PERFORMANCE

Your Work performance is constantly being monitored and recorded. Accordingly, it is important that you complete the Work in accordance with the requirements and meet the specified Work schedule within the timelines dictated by the Purchaser and inform the Purchaser promptly of any changes thereto. Failure to meet such requirements and Work schedule dates will adversely affect your performance rating in the Purchaser's evaluation of your company on future business opportunities.

Item	Material Quantity	Description Unit	Price per unit	Net value
10	 1	Benchmarking study and repot Activ.unit		

Delivery Date : 11/11/2016
Hydro One contact person:
Lisa Lee
416-345-6599
lisa.lee@HydroOne.com

PROPRIETARY

Vendor:
POWER SYSTEM ENGINEERING INC

Purchase order

PO Number:	4500521667
Version:	0
Release Date:	11/07/2016
Contract Number:	

Lynnette Harris

Buyer's Signature

Nov 7/16

TERMS OF REFERENCE

Objective:
To quantify and recommend an appropriate custom stretch factor(s) to apply to Hydro One Distribution's 2018-2022 Custom IR application and meet the expectations of the OEB as set out in its *Utility Rate Handbook*.

Scope of Work:

(1) PSE will conduct a total cost benchmarking empirical analysis for Hydro One Distribution with an appropriate peer group, for the purpose of informing the stretch factor component of the X-Factor which can serve as the basis for a custom index for Hydro One's 2018-2022 Custom IR application for its distribution business. The benchmark evaluation will be based on HON's historical costs through 2015. Given the final business plan in not finalized and the project timeline, we won't be including projected costs that are based on the application. However, we can provide a stretch factor recommendation based on the historical results.

(2) PSE will compare and contrast (a) the approach and results of its approach in #1 above with (b) the approach and results of the PEG total cost benchmarking model that the OEB uses to determine stretch factors for Price Cap applicants and requires distributors complete as part of their distribution applications. In doing so, PSE will discuss the appropriateness of the PEG total cost benchmarking model for Hydro One.

(3) As required, PSE will provide reasonable guidance to Hydro One staff in completing the PEG model for the purpose of predicting the variance between Hydro One Distribution's forecast 2018 costs and its 2018 costs as predicted by the PEG model, consistent with the OEB's filing requirements.

(4) At Hydro One's request, PSE will present, discuss and defend the results of its aforementioned work in a stakeholder session presently scheduled for February 8, 2017 and in Hydro One's Custom IR distribution rate proceeding before the OEB and provide input on the same for Hydro One's written submissions.

Milestones and Deliverables:
PSE will have two written deliverables and hard deadlines: (a) a brief preliminary report outlining the preliminary results of PSE's work and its preliminary recommendations by the end of November, which will inform Hydro One management's advice to its Board of Directors, and (b) a final report by December 31, 2016 which reflects feedback from Hydro One, as PSE deems appropriate. The November report will be brief.

Before mid-November, PSE will provide Hydro One with an outline of its methodology and proposed peer group. The parties acknowledge that this is subject to change based on further research and data gathering.

Tasks that fall within PSE's scope of work will be performed in accordance with Hydro One's application timeline, which has been provided to PSE. Dates are subject to change with Hydro One's prior written approval.

Reporting:
PSE will provide interim progress reports on a bi-weekly basis and provide summary updates, as reasonably requested.

Resourcing:
Steve Fenrick will be the client contact and work execution lead for PSE.

Special Terms and Conditions

Capitalized terms not defined under the Special Terms and Conditions shall have the same meaning ascribed to them under the Standard Commercial Conditions for Consulting and Professional Services (collectively the "Contract"), unless otherwise expressly stipulated. The provisions of these Special Terms and Conditions shall prevail over any provisions under the Standard Commercial Conditions for Consulting and Professional Services to the extent of any conflict or inconsistency.

1.1 Definition of Terms

A-29-2011 (October 2011) Section 1 is hereby amended as follows:

1(2) Delete the entire section and replace with ""**Company**" or "**Contractor**" **-** the person, firm, partnership, corporation or other entity to whom the Purchaser has awarded the Contract;"

1(5) Delete the entire section and replace with ""**Goods and Services Tax**" or "**GST**" means the federal Goods and Services Tax chargeable in accordance with Part IX of the Excise Tax Act (Canada), as amended, in respect of a supply made in a non-participating province."

1(6) Delete the entire section and replace with ""**Harmonized Sales Tax**" or "**HST**" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the Excise Tax Act (Canada), as amended, in respect of a supply made in a participating province."

1(12) Delete the entire section and replace with ""**Purchaser**" – Hydro One Inc. or one of its Affiliates, whichever has been designated in a Contract document;"

1(16) New subsection – ""**Affiliate**" - any entity that directly or indirectly controls, is controlled by, or under common control with a party, and "control" means with respect to any entity, the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such entity, whether through the ownership of voting shares or other ownership interest or by contract or otherwise."

1(17) New subsection – ""**Company Personnel**" includes any director, officer, employee, contractor, subcontractor, supplier or agent of the Company or its affiliates."

1(18) New subsection – ""**Product**" means the materials, machinery, equipment, hardware, assemblies, instruments, devices, goods, Equipment, products, or articles furnished by the Company, as the case may be, or components thereof, the delivery or supply thereof, pertaining to the Contract."

1(19) New subsection – ""**Personal Risk Assessment**" means a documented background check that includes, at a minimum, a confirmation of identity and a seven year criminal history records check that includes current residence and all other locations the individual resided for six consecutive months during the previous seven (7) years, as well as any other verification or reviews as deemed necessary by the Purchaser."

1.2 Elimination of the Ontario Retail Sales Tax

A-29-2011 (October 2011) Section 7 is deleted.

1.3 Assignment or Subcontracting

A-29-2011 (October 2011) Section 17 is deleted and replaced in its entirety with;

Assignment, Subcontracting and Divestiture

17(1) The Consultant shall not assign nor subcontract this contract nor any portion thereof without the prior written consent of the Purchaser. Without limiting any of the Purchaser's rights at law and for greater clarification, the Purchaser may, without the Consultant's consent, assign this contract or any portion thereof to: any holding body corporate, subsidiary body corporate and/or affiliate, as "holding body corporate", "subsidiary body corporate" and "affiliate" are defined under the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44, as amended; any entity formed by corporate reorganization, amalgamation, divestiture or merger of the Purchaser; and/or any entity that acquires the assets or business of the Purchaser.

17(2) Any division, affiliate, group and/or line of business of the Purchaser that is divested from the control of Purchaser by sale of shares, assets, or otherwise ("Divested Business") shall be entitled to continue to order under this Contract and use the licence, service, Equipment and/or Work in accordance with the terms including pricing of this Contract for a transition period of the longer of the Contract term or eighteen (18) months from the effective date of such divestiture ("Transition Period") without being required to enter into a separate agreement or pay the Consultant a separate price to continue to receive or utilize the licence, service, Equipment and/or Work. Notwithstanding the immediately preceding sentence, the Transition Period does not commute the term of any license that has been paid for in accordance with this Contract that extends beyond the Transition Period.

17(3) Notwithstanding anything else in this Contract, during the Transition Period and at no additional charge to the Purchaser or the Divested Business, the Purchaser is entitled to provide services to support the Divested Business which services may include, without limitation, Purchaser purchasing licences, services, Equipment and/or Work under this Contract on behalf of or for the benefit of the Divested Business, and/or allowing the Divested Business access to, and Purchaser using, the licences, services, Equipment and/or Work to facilitate the business purposes of the Divested Business.

1.4 Withholding Tax

A-29-2011 (October 2011) Section 19 is deleted and replaced in its entirety with;

19(a) Purchaser is required to apply withholding tax on certain amounts to be paid or credited to non-residents of Canada in accordance with the rates and conditions set forth in the Income Tax Act (Canada), as amended, and Tax Conventions that Canada has entered into with foreign jurisdictions ("Treaty"). Purchaser must remit such withholding tax to the Canada Revenue Agency (CRA) for payments to non-residents, unless Consultant provides Purchaser with a waiver by the CRA to the Consultant and/or, where applicable, Consultant provides evidence acceptable to the Purchaser that Consultant or its members does not or has not carried on business in Canada through a permanent establishment and are payments not connected to a permanent establishment in Canada.

19(b) Consultant will provide Purchaser, upon request, evidence satisfactory to Purchaser, of Consultant's residency. It is the Consultant's responsibility to file with the CRA any documentation as necessary to obtain any waiver or relief from withholding tax.

19(c) Consultant will indemnify Purchaser for any tax, penalties and interest that may be assessed to the Purchaser by CRA for failure to withhold the required tax from the payments, on a net of tax basis.

19(d) Consultant agrees to notify Purchaser within thirty (30) days of any event that affects Purchaser's obligations with respect to withholding tax.

19(e) Under no circumstances will Purchaser:
(i) "gross up" or make any tax equalization payments of any kind to Consultant; or,
(ii) have any liability for any of the Consultant's income, payroll, or capital (including large corporation) taxes imposed by any governmental authority in connection with this Contract.

1.5 Invoicing

A-29-2011 (October 2011) Section 21 is hereby amended as follows:

21 (a) Replace "30 days" with "45 days"

1.6 Security / Safety Measures

A-29-2011 (October 2011) Section 29 is hereby deleted and replaced as follows:

The following provisions are added to the Contract or in the event that there are conflicting security or safety provisions already included in the Contract, those provisions are deleted and replaced with the provisions set out herein.

29(a) The Company and all Company Personnel shall obey all policies, rules, regulations and procedures established by the Purchaser regarding the assets, information, systems, and premises to which the Company has access and projects for which the Company and Company Personnel perform the Work. The Company agrees to ensure that such Company Personnel complete such training as required by the Purchaser related thereto.

29(b) The Company shall protect Purchaser's assets, property, systems, networks and computer resources to which the Company may have access, against damage including, without limitation, (i) using appropriate authentication and other measures to permit and control access only to necessary individuals (ii) utilizing anti-virus and malicious software prevention tools to detect, deter, prevent and mitigate the introduction, exposure and propagation of malware, (iii) be alert to and immediately notify Purchaser of any security events or incidents, (iv) follow industry standard and Purchaser procedures for protection and secure access, storage, transit, use, destruction and disposal of Purchaser information, and (v) follow all rules and requirements established by Purchaser related thereto.

29 (c) When any Product is provided or Work is to be performed regarding any of the Purchaser's assets, systems, offices, properties, or Project Site, or any Company Personnel are expected to have access to any confidential or proprietary information of the Purchaser, the Company:

(i) upon Purchaser's request, will provide a list of such Company Personnel that require access to any of Purchaser's assets, properties, systems or premises or proprietary or confidential information;

(ii) if asked by the Purchaser, will complete and submit to Purchaser, a Personnel Risk Assessment in respect of relevant Company Personnel as requested by the Purchaser; and

(iii) shall provide and shall be responsible to have Company Personnel provide to the Purchaser such personal and other information as the Purchaser's security and other authorized representatives may reasonably require for the purposes of such security and reference checks as the Purchaser, in its discretion, may deem necessary.

29 (d) Commencement of Work and access to the Purchaser's assets, systems, offices, property, Project Site and/or proprietary or confidential information is subject to the following:

Where any of the Work under the Contract involves the Company or Company Personnel having any of the following:

physical access, or electronic access as a super user (including root, administrator), or access as system support, developer, system control operator or general user access to certain critical assets, cyber assets, system or system control assets or information, or providing Products, patches or updates to such assets, systems or information;

the Company, after submitting a Personal Risk Assessment to the Purchaser, must have first received written approval from the Purchaser that each such Company Personnel requiring such access has, in the Purchaser's determination, acceptable security clearance before commencing or continuing the Work; and, shall require such Company Personnel to present such proof of such approval prior to access to Purchaser's assets, systems, offices, properties, Project Site or any confidential or proprietary information to the extent required by the Purchaser.

29 (e) Notwithstanding any Purchaser approval of a Personal Risk Assessment or permission provided by the Purchaser to access any of Purchaser's assets, systems, offices, property and/or any Project Site or confidential or proprietary information, the Company will remain completely responsible and liable for all actions and failures to act of all Company Personnel and will not be relieved of any of its obligations under this Contract.

29 (f) If any Company Personnel cease to be employed or engaged by the Company, or is reassigned or no longer requires access to Purchaser's assets, properties, systems, premises or proprietary or confidential information for the performance of the Work, or the security status of any Company Personnel changes during the term of the Contract, Company shall immediately notify the Purchaser and shall revoke access and immediately cease using the Company Personnel to perform the Work under the Contract.

29 (g) Where there is a change in the security status of any Company Personnel, the Company will immediately provide an updated Personal Risk Assessment and shall not allow such Company Personnel access to Purchaser's assets, properties, systems, premises or proprietary or confidential information or utilize such Company Personnel for the performance of the Work until such time as the Company receives written approval from the Purchaser. In such an event, the Company shall endeavour to diligently complete the Work in accordance with the schedule set forth in the Contract and, if necessary, will increase the level of effort necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain the schedule.

29 (h) In addition to any other remedy that the Purchaser may have against the Company as a result of the Company's failure to comply with all of the terms set out herein, the Company shall, to the extent that delay in providing the said Work occurs as a result of the non-delivery of signed and witnessed documents that are required by the Personnel Risk Assessment, be liable to the Purchaser for all damages arising out

of the said delay.

29 (i) The Purchaser retains the right to stop all or any part of the Work, remove any Company Personnel, revoke access at any time and/or terminate for cause the Contract should the Purchaser in its sole discretion determine that any Company Personnel is a security risk and/or the information provided in the Personnel Risk Assessment was misleading or incorrect.

1.7 Notices

A-29-2011 (October 2011) Section 32 is hereby amended as follows:

Replace “15th floor, North Tower” with “8th floor, South Tower”

1.8 Volume Discounts

If the Proponent and Hydro One have previously entered into a Volume Discount Agreement, then any contract entered into in relation to this RFP shall be an “Applicable Other Agreement” under such Volume Discount Agreement and all amounts invoiced will be included in such Volume Discount Agreement.

CONTRACT STANDARD

Class	Number	Date
A	29	2011

HYDRO ONE INC.
OR ONE OF ITS SUBSIDIARY CORPORATIONS

STANDARD COMMERCIAL CONDITIONS FOR CONSULTING AND PROFESSIONAL SERVICES

October 2011

CONTENTS

1. **Definition of Terms**

The following terms, wherever used in any contract document, shall mean:

(1) "Conflict of Interest" - means, but is not limited to, any situation or circumstance where, in relation to the performance of its obligations under this contract, the Consultant's other commitments, relationships or financial interests (i) could or could be seen to exercise an improper influence over the objective, unbiased and impartial exercise of its independent judgement; or (ii) could or could be seen to compromise, impair or be incompatible with the effective performance of its obligations under this contract;;

(2) "Consultant" – means the individual, partnership or corporation who has been retained by the Purchaser to provide consulting and/or professional services;

(3) "Contract Price" - the stipulated value or sum of value(s) of the fixed price(s) or upset maximum price(s) for the Work (or any portion thereof) set forth in the contract documents as amended by any Instruction Notice. In the case of time and material contracts, "Contract Price" shall mean the product of the rates

stipulated in the contract multiplied by the estimated number of units of time the rates represent for the term of the contract, subject to any subsequent adjustments for : (i) actual eligible units of time incurred; and, (ii) upset maximum amounts. Contract Price excludes the GST/HST.

(4) "FIPPA" - means the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31, as amended;

(5) "Goods and Services Tax" or "GST" means the federal Goods and Services Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended (the "Excise Tax Act"), and includes the additional tax payable under sub-section 165(2) of the Excise Tax Act in respect of a supply made in a participating province;

(6) "Harmonized Sales Tax" or "HST" - means GST payable for a supply made in a participating province. Ontario is a participating province effective July 1, 2010;

(7) "Hydro One Home Location Area" – means an area within a 75 kilometer radius of 483 Bay Street, Toronto, Ontario M5G 2P5, and such other Hydro One locations in Ontario designated as such in any of the documents forming part of this contract;

(8) "Instruction Notice" – a formal executed written document issued by the Purchaser's representative formally amending the Purchase Order in any respect. Any other document purporting to be an instruction notice will be considered invalid;

(9) "Personal Information" means recorded information about an identifiable individual or that may identify an individual;

(10) "Proposal" – means the Consultant's submission in response to the Purchaser's Request for Proposal Documents.

(11) "Request for Proposal Document(s)" or "RFP" - the documents issued by the Purchaser calling for tenders, responses, or proposals for the performance of the Work or for the prequalification to perform the Work, as further stated in the said documents;

(12) "Purchaser" – means Hydro One Inc. or one of its subsidiaries, whichever of those corporations has been designated in a contract document;

(13) "Record" - any recorded information, including any Personal Information, in any form: (a) provided by the Purchaser to the Consultant, or provided by the Consultant to the Purchaser, for the purposes of this contract; or (b) created by the Consultant in the performance of this contract; and shall include or exclude any information specifically described in the purchase order;

(14) "Unfair Advantage" - any conduct, direct or indirect, by the Consultant at the procurement/bidding stage that may result in gaining an unfair advantage over other parties in the procurement/bidding process, including but not limited to (i) possessing, or having access to, information in the preparation of its Proposal that is confidential to the Purchaser and which is not available to other competitors, (ii) communicating with any person with a view to influencing, or being conferred preferred treatment in, the procurement process, or (iii) engaging in conduct that compromises or could be seen to compromise the integrity of the procurement process and result in any unfairness, including, without limitation, conduct, agreement, or concerted practice between the Consultant and another company or person to, among other things, create a fake bid/submission for comparative purposes, or require a competitor to refrain from bidding, or require a competitor to bid in a certain manner, or share details about their bid, including how they intend to bid; and,

(15) "Work" - all labour, materials, equipment, deliverables, documentation, services, tools, supplies, and acts required to be done or supplied.

2. **Contract Documents and Order of Precedence**

(a) The contract documents shall consist of (1) the Purchaser's Purchase Order ("Purchase Order"); (2) Clarification Documents (if any) agreed to and incorporated into the Purchase Order; (3) Insurance Requirements' (4) Special Terms and Conditions; (5) this Contract Standard (A-29-2011); (6) the Consultant's Proposal and (7) the Request for Proposal Documents (other than those listed above). These contract documents shall, to the extent of any inconsistency or conflict, take precedence in the order in which they are named.

Appendices and addenda to any contract document shall be considered part of such document. The contract documents form this contract.

(b) These documents are subject to subsequent amendments to this contract, in the form of Instruction Notices or Change Orders, which shall take precedence over the documents amended thereby.

(c) No agent, employee or other representative of the Purchaser has authority to make any promise, agreement or representation not incorporated into a contract document, and no promise, agreement or representation whenever made shall bind the Purchaser unless so incorporated formally through the Instruction Notice or Change Order.

(d) The contract documents and the Work as specified therein shall be interpreted to include all Work reasonably required to provide a result that is fit for the Purchaser's purposes.

3. **The Purchaser's Representative**

The Purchaser shall inform the Consultant as to the identity of its authorized representative, to whom all correspondence, reports and documents shall be addressed. No acceptance, instruction, approval or statement by the Purchaser's authorized representative or by any other representative of the Purchaser shall relieve the Consultant from responsibility for proper performance of the Work.

4. **FIPPA Records and Compliance**

(a) The Consultant and the Purchaser acknowledge and agree that FIPPA applies to and governs all Records and may require the disclosure of such Records to third parties. Furthermore, the Consultant agrees:

(i) to keep Records secure;

(ii) to provide Records to the Purchaser within seven (7) calendar days of being directed to do so by the Purchaser for any reason including an access request or privacy issue;

(iii) not to access any Personal Information unless the Purchaser determines, in its sole discretion, that access is permitted under FIPPA and is necessary in order to perform the Work;

(iv) not to directly or indirectly use, collect, disclose or destroy any Personal Information for any purposes that are not authorized by the Purchaser;

(v) to ensure the security and integrity of Personal Information and keep it in a physically secure and separate location safe from loss, alteration, destruction or intermingling with other records and databases and to implement, use and maintain the most appropriate products, tools, measures and procedures to do so;

(vi) to restrict access to Personal Information to those of its directors, officers, employees, agents, partners, affiliates, volunteers or subcontractors who have a need to know it for the purpose of providing the Work and who have been specifically authorized by the Purchaser authorized representative to have such access for the purpose of providing the Work;

(vii) to implement other specific security measures that in the reasonable opinion of the Purchaser would improve the adequacy and effectiveness of the Consultant's measures to ensure the security and integrity of Personal Information and Records generally; and,

(viii) that any confidential information supplied to the Purchaser may be disclosed by the Purchaser where it is obligated to do so under FIPPA, by an order of a court or tribunal or pursuant to a legal proceeding;

(b) The provisions of this Section shall prevail over any inconsistent provisions in this contract.

(c) The provisions of this Section shall survive any termination, cancellation, or expiry of this contract.

(d) The Purchaser may immediately terminate this contract upon giving notice to the Consultant where the Consultant breaches any provision in this Section FIPPA Records and Compliance.

5. **Pricing**

(a) The Contract Price shall be as referenced in the Purchase Order. Unless expressly stated otherwise in the Purchase Order, as part of the Contract Price, the fixed price, upset maximum (not to exceed) price and/or rates shall be deemed to be gross prices and/or rates. For greater certainty, as part of the Contract Price, the said gross prices and/or rates will include all applicable taxes (except for GST/HST), premiums, levies, duties, and other charges of every kind attributable to the Work, whether or not they are statutory or otherwise, including, without limitation, in relation to the following: insurance; Workplace Safety and Insurance Board (WSIB) or those of a similar body; payroll; health plan; dental plan; drug plan; employment insurance; vacation pay; sick time; bonus pay; Canada Pension Plan; any other pension plan; and, tax equalizations.

(b) Only the GST/HST shall be shown separately as an extra to the Contract Price.

(c) The Consultant's prices and/or rates in (a) above shall be deemed to compensate the Consultant for all corporate, executive, and management expenses, general administration expenses, including the services of a project administrator (unless otherwise expressly specified in writing and referenced in the purchase order), accounting, employee relations, clerical staff, secretarial support, normal stationery and office supplies, local telephone, rent, utilities, taxes, depreciation, and Consultant's fees.

(d) Consultant personnel designated as manager or above, including Project Manager or similar title or function, shall not be charged to the Work unless they are engaged in making a substantial direct technical contribution thereto, or unless otherwise specified in writing. Any effort which contemplates such charges shall require the Purchaser's prior written authorization.

(e) The following applies to upset maximum (not to exceed price) pricing and time and material pricing. It does not apply to fixed prices:

(i) The use of overtime hours on the Work shall be subject to the Purchaser's prior written approval. Overtime hours shall be compensated at straight time hourly rates. The Purchaser shall be entitled to a reasonable reduction in overhead rates to take the increase in billable hours into account.

(ii) The services of other consultants shall not be employed without the prior written approval of the Purchaser. Where such approval is obtained, the Consultant shall be reimbursed, without mark-up of cost, at the per diem or hourly rate charged by the other consultant(s).

(ii) Contract staff, employed at the Consultant's premises and under its direct supervision, shall be reimbursed at the per diem or hourly rate cost to the Consultant, without mark up, unless otherwise agreed upon in writing with the Purchaser.

(f) If Purchase Order expressly allows for recoverable expenses, the following expenses will be recoverable at cost, provided they are necessary and reasonable, and were directly and properly incurred for the performance of the Work:

(i) traveling and lodging expenses for Consultant personnel while away from their home office (as established for the purpose of this contract), provided that the anticipated expenses are approved in writing in advance by the Purchaser. No traveling or lodging expenses will be reimbursable if the Consultant has an office within the Hydro One Home Location Area and Consultant personnel is required to travel to any location within the Hydro One Home Location Area;

(ii) special drawings or reproduction charges;

(iii) printing or copying of documents for delivery to the Purchaser in excess of 15 sets; and,

(iv) other items approved in advance in writing by the Purchaser.

Recoverable travel-related expenses and other expenses shall also be subject to the Purchaser's *Travel and Expense Guidelines* in effect from time-to-time.

(g) Under no circumstances will any expenses be recoverable by the Consultant from the Purchaser, either directly or indirectly, for any hospitality, incidental, or food or beverage expenses incurred by Consultant personnel, or anyone acting on behalf of Consultant, including but not limited to expense in respect of:

(i) meals, snacks and beverages;
(ii) gratuities;
(iii) laundry, dry cleaning and valet services;
(iv) dependant care; and,
(v) personal telephone calls.

6. **Accounts and Right to Audit**

The Consultant shall keep proper accounts and records of the Work in form and detail satisfactory to the Purchaser. Such accounts and records, including invoices, receipts, time cards and vouchers shall at all reasonable times be open to audit, inspection and copying by the Purchaser. Accounts and records shall be preserved and kept available for audit until the later of: (i) expiration of two years from the date of completion of the Work and all warranty obligations under this contract; and, (ii) the date of early cancellation of the Work under Section 25 or termination of the Work under Section 27hereof.

7. **Elimination of the Ontario Retail Sales Tax**

The Ontario Retail Sales Tax ("ORST") was eliminated effective July 1, 2010. The Consultant covenants and agrees that any cost savings as a result of the elimination of the ORST will be fully reflected in the amounts charged to the Purchaser under this contract. The Consultant will provide such information as the Purchaser may reasonably request to confirm that the full effect of all savings as a consequence of the elimination of the ORST are reflected in the prices, fees, and costs charged to the Purchaser.

8. **Proprietary Rights, Confidentiality**

(a) Both parties retain all rights to methodology, knowledge, and data brought to the Work and used therein. No rights to proprietary interests existing prior to the start of the Work are passed hereunder other than rights to use same as provided for below. The Consultant shall not knowingly incorporate into the Work any data, software or hardware the use of which by the Purchaser violates the proprietary rights of third parties.

(b) All right, title, and beneficial ownership interests to all intellectual property, including copyright, of any form, including, without limitation, discoveries (patented or otherwise), software, data (hard copies and machine readable) or processes, conceived, designed, written, produced, developed or reduced to practice in the course of the Work shall irrevocably vest in and remain with the Purchaser. The Consultant shall not do any act which may compromise or diminish the Purchaser's interests as aforesaid.

(c) The Consultant grants to the Purchaser a non-exclusive, paid-up, irrevocable, perpetual license to use any data and other proprietary items incorporated into the Work by the Consultant hereunder. Provided it is part of the Consultant's proposal and incorporated into this contract, the Consultant may reserve the right to incorporate into the Work data or other proprietary property for the use of which the Consultant wishes to charge a fee stipulated in the said proposal and incorporated into this contract. If the Consultant's proposal does not contain the fee, the Consultant shall be deemed to have waived any such fee. The Purchaser shall have the right to exploit such data and property and to license same to third parties provided that such licenses contain reasonable reservations of proprietary rights in favor of the Consultant (which may be included in a general reservation, but shall contain the same order of legal protection as the Consultant uses when distributing such data or property to third parties) or provided the use of same does not reveal information proprietary to the Consultant.

(d) Except as required in the performance of the Work or as authorized in writing by the owner, each party shall keep confidential all personal, customer, and proprietary information of the other ("confidential information"), including, without limitation, all unpublished business and technical information, papers, or records, however produced. The Consultant remains responsible if any confidential information is disseminated to its sub-consultant. These obligations of confidentiality shall survive completion and/or early termination or cancellation of this contract and shall apply for a period of five years from the date of the last invoice submitted by the Consultant hereunder. In addition to the foregoing, if requested by the Purchaser, the Consultant shall sign a more extensive and stringent confidentiality agreement. In all cases, if requested by the Purchaser, the Consultant agrees to obtain for the Purchaser the written agreement of the Consultant's employees, sub-consultants, and agents to protect all confidential information.

9. **Purchaser's Code of Business Conduct; Conflict and Interested Persons**

(a) The Consultant acknowledges and agrees that the Purchaser's directors, officers, employees, agents, representatives, and business partners are bound by the Purchaser's Code of Business Conduct.

(b) The Consultant will not take any action that would cause the Purchaser or any of its directors, officers, employees, agents, representatives, or business partners to be in breach of any of the obligations set out in Hydro One's corporate Code of Business Conduct. A current copy of the code may be reviewed by downloading the electronic document by following the appropriate link at the following hyperlink: http://www.HydroOne.com/CodeofConduct

(c) In connection with any of the Work under this contract, the Consultant covenants and agrees, not to offer or give directly or indirectly to any of the Purchaser's employees or representatives, or their immediate family members (including their common law relationships) known to the Consultant to the best of its knowledge and belief, each of the foregoing persons an "Insider", collectively "Insiders", any of the following:

(i) any form of bribe or kickback;

(ii) gifts of cash, gift certificates, services, discounts, or loans;

(iii) any gift, entertainment, or similar type of benefit that does not serve a legitimate business purpose; or

(iv) any gift, entertainment, or similar type of benefit that may compromise or appear to compromise their ability to make business decisions in the best interest of the Purchaser.

(d) The Consultant further represents, warrants, and covenants that, at the commencement of this contract, and throughout its term, to the best of the Consultant's knowledge and belief, no Insider has (or will have) an interest (whether directly or indirectly, or personal, or financial), in the supplies, work, or business to which this contract relates, or in any portion of the profits thereof, or in any monies to be derived therefrom ("Insider's Interest"); however, there is no breach of the foregoing where:

(i) at the time of entering into this contract, the Consultant has disclosed all relevant facts known to it concerning the Insider's Interest, and the Purchaser has provided the Consultant with a written determination, made at the Purchaser's sole and absolute discretion, that the Insider's Interest:

A. does not have potential for real or perceived Conflict of Interest, or

B. has a potential for real or perceived Conflict of Interest but it can be managed in a way that protects the integrity and reputation of the Purchaser, and would withstand the test of reasonable and independent scrutiny, and a suitable method of monitoring and managing such real or perceived conflict has been determined and is implemented.

(ii) the Consultant is a publicly-traded company that offers its registered securities to the general public and the Insiders, collectively, have an insignificant interest in the stock of that company, not to exceed a total of five per cent of the outstanding stock of the company.

10. <u>Conflict of Interest in Performance of Work and Unfair Advantage</u>

(a) The Consultant represents and warrants that there is no Conflict of Interest between the performance of the Work outlined in the contract documents and its performance of Work and provision of services to other customers, and this warranty shall survive the execution of this contract.; during the performance of the Work, should any such Conflict of Interest be discovered, the Consultant covenants to immediately advise Purchaser of same, and Purchaser may, at its discretion, terminate this contract, or any part thereof, for cause under Section 10 herein.

(b) The Consultant further represents, warrants, and covenants that, prior to the award of this contract, to the best of the Consultant's knowledge and belief, no Unfair Advantage existed. Should the Purchaser discover the Consultant's failure to have disclosed all material details in connection with any Unfair Advantages at the procurement/bidding stage, the Purchaser may, at its discretion, terminate this contract, or any part thereof, for cause under Section 10 herein.

11. <u>Surety Bonds – Performance, Labour and Material Payment; Other Security</u>

(a) Surety Bond - At Purchaser's request, at any time, and from time to time, the Consultant may be required to furnish one or more surety bonds (being a performance bond(s) and/or a labour and material payment bond) in a form satisfactory to the Purchaser and in an amount up to 100 percent of the Contract Price.

The surety shall be acceptable to the Purchaser and licensed to issue such surety bonds in the Province of Ontario. The Consultant shall maintain the surety bonds in good standing until the fulfillment of its obligations under this contract.

(b) Other Security - At Purchaser's request, at any time, and from time to time, the Consultant may be required to furnish other security for contract performance, in a form and amount satisfactory to the Purchaser, such as a guarantee by a parent company (if applicable), a bank letter of credit, bank guarantee, a monetary deposit, or personal property security documentation.

(c) Reimbursement for Cost of Surety Bonds –

(i) If not requested for in the Tendering Documents, or,

(ii) if requested in the Tendering Documents and the cost thereof is shown separately in the Tender,

then following the issuance of a surety bond, the Consultant will be reimbursed for the cost thereof (if any, and without mark-up of cost by Consultant) at rates no more than the prevailing industry rates, 30 days after receipt of actual invoice accompanied by evidence of payment to the surety. After payment of the initial premium, the Consultant shall at its expense maintain the surety bond, and/or other security for contract performance in good standing for the duration of this contract, until fulfillment of its obligations under this contract. There will be no reimbursement of costs in relation to surety bonds in other circumstances or for the costs of any other security.

(d) Failure to Furnish Surety Bonds or Other Security - Failure to furnish the surety bonds, or other security within two weeks from the date of request, made at any time, therefor by the Purchaser, shall make any award of contract by the Purchaser subject to withdrawal and shall also entitle the Purchaser to the payment of any damages it may suffer as a result. If this contract has already commenced, the failure to furnish such surety bonds or other security will, at the Purchaser's sole discretion, entitle the Purchaser to terminate this contract for cause.

12. **Inspection and Warranty**

The Purchaser's authorized representative shall have the right, without any obligation to exercise that right, to inspect the Work at all times and may reject any part thereof which is found to be not in accordance with this contract and any applicable standards, including without limitation, applicable professional and safety standards, and any standards customary in the industry, and those imposed by law, including statutes, regulations, orders, guidelines, and judgments. However, the exercise by the Purchaser of its right to inspect shall not be construed to diminish any of the Consultant's duties and obligations under this contract. Any of the Work so rejected shall be promptly redone by the Consultant at its expense. This shall include, but not be limited to, all drawings and data prepared by the Consultant under this contract which are found, within a period of one year from date of transmittal to the Purchaser, to be incomplete or inaccurate due to a failure to comply with said standards.

13. **Escorted Access**

(a) If any of the Work or services provided pursuant to this contract requires entry to one or more of the Purchaser's transmission stations, switching stations, distribution stations or control centres by the Consultant or its sub consultants or any person providing services to, or acting on behalf of, the Consultant or its sub consultants (collectively, the "Entrants"), no Entrant shall be permitted entry to any of the said premises unless accompanied at all times by an employee of the Purchaser or another person appointed by the Purchaser to provide such accompaniment. It shall be the responsibility of the Consultant to arrange such accompaniment, and the Consultant shall ensure that no Entrant shall enter or attempt to enter the said premises without such accompaniment. The Purchaser may, at its sole discretion, waive in writing the requirement for the Consultant to be escorted when entering transmission stations, switching stations, and distribution stations.

(b) The Consultant shall obey all rules and regulations established by the Purchaser regarding the premises to which the Consultant has access and projects on which the Consultant performs the Work.

14. **Safety**

If the Work includes field work, the Consultant shall comply with all relevant safety rules and regulations, including, without limiting the generality of the foregoing, those established by the Purchaser.

15. **Purchaser's Limitation of Liability**

Subject to all other exclusions and limitations anywhere in the contract documents, the Purchaser's maximum liability to the Consultant, or anyone claiming through the Consultant, shall not exceed an amount equal to the lesser of: (i) the Contract Price, and (ii) one hundred thousand dollars ($100,000). In no event shall the Purchaser be responsible for any losses or damages that are indirect, consequential, punitive, or for economic loss, loss of revenues, loss of profits, loss of business opportunity, or as a result of fines levied by governmental or regulatory authorities or the courts.

16. **<u>Consultant's Manager/Staff: Consultant Not Agent</u>**

(a) Prior to commencing the Work, the Consultant shall appoint a manager or professional as Project Manager who will be responsible for the administration and co-ordination of all phases of the work. All staff of the Consultant employed on the project shall have the knowledge, abilities, experience, and qualifications required for the Work and shall be committed to the Work. The Consultant must provide such additional support as may be required from time to time for the proper performance of the Work, and as may be necessary for completion of the Work within any completion date.

(b) Changes to Consultant personnel and support staff shall require the Purchaser's prior written approval. The Purchaser may request, at its discretion, that the dedicated project individual(s) be changed. The Consultant shall endeavor to accommodate such requests.

(c) The Consultant shall have no authority to bind the Purchaser or to assume or create any obligation or responsibility expressed or implied on the Purchaser's part, or in its name, nor shall it represent to anyone that it has such power or authority, except as expressly provided in this contract.

(d) The Consultant is independent from the Purchaser at all material times. Any subcontractor performing services on behalf of the Consultant shall be deemed to be an "agent or employee" of the Consultant, and under no circumstances be considered to be an agent or employee of the Purchaser.

17. **<u>Assignment or Subcontracting</u>**

Neither party shall assign or subcontract this contract or any portion thereof without the prior written consent of the other; but, notwithstanding the foregoing, the Purchaser may, without the Consultant's consent, assign this contract or any portion thereof to one an affiliate, as "affiliate" is defined under the Ontario *Business Corporations Act*, R.S.O. 1990, c. B.16, as amended.

18. **<u>Offshore Consultants</u>**

The Consultant is responsible for applying to the Government of Canada for admission of personnel into Canada and for obtaining work permits where required. The Consultant will be required to obtain customs clearance and pay duties and taxes where applicable, for goods or tools used in the performance of the Work or imported into Canada. Assistance with clearance of goods will be provided by the Purchaser if requested.

19. **<u>Withholding Tax</u>**

(a) Certain amounts paid or credited to non-residents of Canada are subject to income tax withholding in accordance with rates and conditions set forth in the *Income Tax Act* and tax treaties. This tax is remitted to Canada Revenue Agency (CRA).

(b) For U.S.-based Consultants:

(i) a 15% withholding tax is required on the gross amount payable for services rendered in Canada (e.g. consulting fees, maintenance fees).

(ii) a withholding tax is required on rentals, royalties and similar payments (including payments for the rights to use computer software). The rate is 25% but is generally reduced to 10% under the Canada-U.S. Tax Convention, and is zero in certain circumstances. Where the Consultant either provides representation acceptable to the Purchaser, that it does not carry on or has not carried on business in Canada through a permanent establishment ("p.e.") and that the payments are not effectively connected to such p.e., or alternatively, the Purchaser is provided with a CRA waiver from the withholding requirement, the Purchaser will apply the 10% withholding or zero withholding to the payments, as applicable. In either case, the Consultant must indemnify the Purchaser for any tax, penalties and interest that may be assessed to the Purchaser by the CRA for failure to withhold the required tax (i.e. 25%) from the payments. The Consultant agrees to notify the Purchaser within thirty days of commencing to carry on a business in Canada through a permanent establishment to which the payments due under this contract are effectively connected.

(iii) Each February, the Purchaser issues CRA forms, either a NR4 or T4A-NR (depending upon the nature of the payment made) to all non-resident Consultants who were paid by the Purchaser during the previous year.

(c) Under no circumstances will Purchaser:

(i) make any tax equalization payments of any kind to Consultant; and,

(ii) have any liability for any of the Consultant's income, payroll, or capital (including large corporation) taxes imposed by any governmental authority in connection with this contract.

20. **Equipment Owned by the Purchaser**

(a) Equipment authorized by the Purchaser for purchase by the Consultant or supplied to the Consultant by the Purchaser shall be used solely in the performance of the Work in a manner authorized by this contract; any use of the equipment for any other purpose or manner is strictly prohibited and will constitute an improper use of the Purchaser's equipment. The Consultant acknowledges and agrees that any improper use of the Purchaser's equipment will constitute a breach of the Consultant's duty of good faith and loyalty to the Purchaser, and a breach of this contract. In addition to all other rights and remedies available to the Purchaser, at Purchaser's sole and absolute discretion, improper use of the Purchaser's equipment will be cause for immediate termination of this contract under Section 20 herein. For any improper use of Purchaser's equipment, the Consultant will pay the Purchaser, as liquidated damages and not as a penalty, an amount equal to the greater of (i) five thousand dollars, or (ii) the amount of revenues generated, directly or indirectly which, the improper use of such equipment facilitates. Any damage, loss, or other diminution in value of equipment shall be additional to liquidated damages. Title to such equipment shall remain with the Purchaser. Equipment shall be clearly identified as property of the Purchaser. The Consultant shall be responsible for safeguarding such equipment (including without limitation, safety of Consultant and others from the equipment) while in its custody or control, maintaining a system of inventory control acceptable to the Purchaser. The Purchaser shall have reasonable access to the premises of the Consultant for the purpose of verifying records and auditing inventories of such equipment.

(b) Following completion of the Work or early cancellation or termination of this contract, the Consultant shall, unless otherwise directed, make all such equipment immediately available for pickup by the Purchaser. The Consultant shall be liable for the repair or replacement of all equipment owned by the Purchaser which becomes damaged or lost while in the custody or control of the Consultant. The Consultant shall maintain insurance, in which the Consultant and the Purchaser shall be named jointly as insured, covering the full replacement value of all such equipment against the risk of loss or damage.

21. **Invoicing**

(a) Charges for services rendered and reimbursable expenses incurred may be submitted monthly unless otherwise specified in the purchase order. Invoices shall be in such detail and format as specified from time to time by the Purchaser. Payment of acceptable invoices shall be made 30 days after receipt thereof.

(b) The GST/HST, together with the registration number for same, shall be shown separately on all invoices. The Consultant shall deduct all recoverable GST/HST paid from reimbursable expenses before adding GST/HST to amounts to be invoiced to the Purchaser.

(c) If at any time during the performance of the Work there are deficiencies in the Work, including non-delivery of an acceptable final report, the Purchaser shall have the right to withhold from any invoice an amount that, in the Purchaser's opinion, takes into account the deficiencies. Any amount withheld will be paid 30 days after receipt of invoice submitted after the Purchaser's approval of the correction of deficiencies.

22. **Insurance and WSIB Coverage**

In connection with the performance of any Work pursuant to these terms and conditions, the Consultant covenants and agrees to maintain insurance coverage, as well as registration and coverage under *Workplace Safety and Insurance Act, 1997*, S.O. 1997, as amended ("WSIB Coverage"), in accordance with the terms and limits of the Purchaser's document titled "Insurance Requirements", or in accordance with such other document identified in the purchase order that requires the

Consultant to maintain insurance coverage and WSIB Coverage.

23. **Progress Reports**

The Consultant shall forward to the Purchaser on or before the 20th day of each month, a progress report in such form and detail as may reasonably be requested by the Purchaser, showing the progress of the Work to the end of the preceding month. Such report shall also include a summary of the costs to date, estimated cost to completion of the Work, an explanation of any variance from the original estimate, and shall disclose accurately and clearly any other facts concerning the transaction which the Consultant believes are relevant. The Consultant shall notify the Purchaser immediately upon having expended or committed 80% of the authorized funds.

24. **Completion of the Work**

The Consultant shall complete the Work in a diligent, professional, prudent, and workmanlike manner in accordance with the schedule set forth in this contract and, if necessary, will increase the level of effort/resources necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain schedule.

25. **Contract Cancelation**

(a) The Purchaser shall have the right, which may be exercised at any time, and from time to time, to cancel this contract, or any uncompleted or unperformed portion of the Work or part thereof.

(b) Unless otherwise agreed in writing between the Consultant and the Purchaser, in the event of such cancellation, the Purchaser shall be obligated to pay the Consultant only for reasonable, necessary, unavoidable, and unrecoverable direct costs incurred by Consultant by reason of any undertakings or commitments by Consultant prior to the expiry of the notice period. Such costs are to be supported by audit, if required by Purchaser, performed by auditors acceptable to the Purchaser. The Purchaser will not be liable for any other amounts. The Consultant shall not undertake any forward commitment after receipt of notice of cancellation.

(c) Title to all Work for which reimbursement is made shall vest with the Purchaser. The above payment procedure shall not apply to situations in which the Purchaser is entitled to terminate this contract by reason of default by the Consultant in the performance of its obligations.

(d) The Purchaser shall not be liable to the Consultant for loss of anticipated profit on the cancelled portion or portions of the Work, or any other incidental, indirect or consequential damage.

(e) The Consultant shall not undertake any forward commitment after receipt of notice of cancellation.

(f) The remedies in this Section 25 shall be the Consultant's sole and exclusive remedies for cancellation of this contract.

26. **Suspension of Work**

(a) The Purchaser shall have the right, which may be exercised from time to time without invalidating this contract, to delay the start date or suspend performance by the Consultant of any part or the whole of the Work for such reasonable period of time as the Purchaser may notify the Consultant. Except to the extent any such delay or suspension arises from default by the Consultant, the Purchaser shall pay to the Consultant the pre-approved actual necessary, reasonable, unrecoverable, and unavoidable extra direct expenses incurred by the Consultant arising from the suspension, provided that in no event will the Purchaser be liable to the Consultant for loss of profit, loss of revenues, interest loss, loss of business opportunity, or any other damages or loss occasioned to the Consultant by reason of any such Work suspension. Such extra expenses shall be supported by audit, if required by the Purchaser, carried out by auditors acceptable to the Purchaser, prior to payment of same.

(b) The resumption and completion of the Work after the suspension shall be as established by the parties having regard to the duration of such delay or suspension, and the nature of the Work.

27. Default by Consultant - Termination

(a) Without limitation, the following actions by or circumstances relating to the Consultant shall constitute default on the part of the Consultant:

(i) committing any act of insolvency or bankruptcy, voluntary or otherwise;

(ii) having a receiver appointed on account of insolvency or in respect of any property;

(iii) making a general assignment for the benefit of creditors;

(iv) failing to pay accounts relating to the Work as they come due;

(v) failing to prosecute the Work with skill and diligence;

(vi) assigning or subletting this contract or any portion thereof without the required consent;

(vii) failing or refusing to correct defective or deficient Work;

(viii) being in breach of sub-Section 9(d)

(ix) failing to disclose all material details in respect of an Unfair Advantage during the procurement/bidding stage, or of a Conflict of Interest at any point, or being in breach of Section 10(b) hereof;

(x) being otherwise in default in carrying out any of its obligations under this contract, whether such default is similar or dissimilar in nature to the causes listed previously.

(b) Notice that the Consultant is in default shall not be required if the default relates to the bankruptcy, insolvency or financial instability of the Consultant. Ten days' written notice shall be given in the event of other defaults.

(c) If the Consultant is in default under this contract, then the Purchaser shall be entitled to:

(i) take possession of all of the Work in progress;

(ii) eject and exclude from the Purchaser's premises all personnel of the Consultant and any sub-consultant;

(iii) terminate the Purchaser's utilization of the Consultant to perform the Work;

(iv) finish the Work by whatever means it may deem appropriate under the circumstances;

(v) withhold any further payments to the Consultant until its liability to the Purchaser is ascertained.

(d) The Consultant shall be liable to the Purchaser for:

(i) the extra expense of finishing the Work, including compensation to the Purchaser for additional managerial and administrative services;

(ii) the cost of correcting defects (if any) in that portion of the Work performed by the Consultant; and

(iii) all other loss, damage and expense occasioned to the Purchaser by reason of the Consultant's default.

(e) Any action by the Purchaser under this Section 27 shall be without prejudice to the Purchaser's other rights or remedies under law or under any surety bond or other security held by the Purchaser for performance of this contract by the Consultant.

(f) The Consultant's performance under this contract, whether or not a default has occurred, may impact the Purchaser's assessment of the Consultant to perform future work by the Purchaser or its affiliates.

28. **Qualifications**

(a) The Consultant, the supervisor and employees, representatives and agents, and sub-consultants must be able to demonstrate that he, she or it has Qualified and Competent workers with suitable experience and adequate equipment to carry out the specified work safely. The Consultant shall rectify immediately safety rule violations by its employees and sub consultants. Refusal to do so and or repeated violations will result in permanent removal of the offender from the work or cancellation of this contract. The definitions of Qualified and Competent are as follows:

(i) "Qualified" means a person who is accepted as satisfactory in reference to experience, personal competency, and familiarity with rules, procedures, apparatus, and dangers involved in the work.

(ii) “Competent” means a person who:

A. is qualified because of his or her knowledge, training and experience to organize and perform the work;

B. is familiar with the provisions of the *Occupational Health and Safety Act*, R.S.O. 1990, c.O.1, as amended, and the Purchaser’s corporate policies and procedures set forth herein that apply to the work;

C. has the requisite knowledge of any potential or actual danger to health and safety in the workplace;

D. is fit to perform the work, both physically and mentally; and,

E. is at least 18 years of age or such higher age as may be prescribed by law.

29. **Security/Safety Measures**

(a) Site Access

(i) The Consultant may, during the term of this contract, be required to complete and submit to Purchaser, Personnel Risk Assessment Forms as provided in the Request for Proposal Documents, for any and all personnel expected to have access to any of the properties, offices, or confidential or proprietary information of the Purchaser for the purpose of assisting the Consultant to provide any of the said services.

(ii) Once security checks have been successfully completed, the Purchaser will issue letters to the Consultant’s representative authorizing site access to each applicant. The Purchaser’s letter must be presented prior to access to the Purchaser’s sites.

(iii) The aforementioned security requirements shall remain in force during the entire term of this contract. Notwithstanding anything else in this contract:

A. If stated in this contract and/or If so instructed by the Purchaser in writing, the Consultant shall not commence providing the said services prior to the Consultant's receipt of the Purchaser’s letters authorizing site access to each applicant. The Purchaser’s letter must be presented prior to access to the Purchaser’s sites;

B. if the security status changes of any personnel, employee or subcontractor employee during the term of this contract, the Consultant shall not continue providing the said services utilizing the employee or subcontractor employee until such time as the Consultant receives from the Purchaser a letter authorizing site access based on said changed security status. In such an event, the Consultant shall diligently endeavour to complete the Work in accordance with the schedule set forth in this contract and, if necessary, will increase the level of effort necessary to ensure the schedule is maintained. Any price or funding limitations shall not be exceeded without the Purchaser's prior written authorization, notwithstanding any extra efforts required to maintain schedule. The Purchaser may in its sole discretion and without any cost to the Purchaser refuse access to the Purchaser’s properties, offices, or confidential or proprietary information to any any worker (Consultant personnel, employee or subcontractor employee) with a criminal record. If the Purchaser does not refuse access to the Project Site to any such worker with a criminal record, the Consultant will not be relieved of any of its obligations under this contract respecting that worker and the Consultant will remain completely responsible for all actions and failures to act of all workers of the Consultant and any subcontractors while at the Project Site; and,

C. in addition to any other remedy that the Purchaser may have against the Consultant as a result of the Consultant's failure to comply with all the terms of this Section, the Consultant shall, to the extent that delay in providing the said services occurs as a result of the non-delivery of signed and witnessed Personnel Risk Assessment, Authorization and Release forms as required by (i) and (ii), be liable to the Purchaser for all damages arising out of the said delay.

(b) Security

(i) The Consultant shall protect Purchaser Property and computer resources against damage and waste including, without limitation, following all rules established for protection against computer viruses.

(ii) The Purchaser retains the right to terminate for cause this contract or stop the Work at any time should the Purchaser in its sole discretion determine that any Consultant Staff Member is a security risk and/or the information provided in the Personnel Risk Assessment form or any other security related documentation was misleading or incorrect.

(iii) The Consultant shall obey all rules and regulations established by the Purchaser regarding the premises to which the Consultant has access and projects on which the Consultant performs the Work.

30. **<u>Indemnification</u>**

The Consultant shall indemnify and hold harmless the Purchaser and its agents, employees, directors, officers, shareholders, partners and affiliates, from and against all claims, demands, losses, costs, expenses (including, but not limited to court costs, legal fees and disbursements) damages, actions, suits, proceedings, or fines (imposed by third parties, including, without limitation, the provincial or federal governments or the courts thereof or any governmental agencies), that arise out of or result from or are attributable to the Consultant's performance of this contract (hereinafter called "claims") or relating to environmental, health or safety hazard(s) or condition(s) to the extent that such claims are caused by breach of contract or negligent or wilful acts or omissions of the Consultant, any sub consultant and anyone directly or indirectly employed by any of them or anyone for whose acts any of them may be liable. The said indemnification shall apply whether the claims are in tort or in contract and whether the claims are for direct damages, indirect damages, punitive damages, economic loss, loss of revenues, loss of profits, or as a result of fines.

31. **<u>Interpretation of Contract Liability</u>**

If at any time there is more than one legal entity constituting the Consultant, their covenants under this contract shall be considered to be joint and several and apply to each and every entity. If the Consultant is or becomes a partnership or joint venture, each legal entity who is a member or becomes a member of the partnership or joint venture or its successors is and continues to be jointly and severally liable for the performance of the services and all the covenants of the Consultant pursuant to this contract whether or not that entity ceases to be a member of the partnership, joint venture or its successor.

32. **<u>Notices</u>**

(a) Notices to the Purchaser shall be addressed to the General Counsel, Hydro One Inc., 483 Bay Street, 15th Floor, North Tower, Toronto, Ontario M5G 2P5. Such notices shall be effective upon receipt.

(b) Notices to the Consultant shall be effective upon delivery to the Consultant or the sending of same by registered post to the Consultant’s last address recorded with the Purchaser.

33. **<u>Re-employment of Former Employees</u>**

(a) The Purchaser has a policy restricting the involvement, in the Purchaser's contracts, of former employees of Ontario Hydro or Hydro One Inc. or its subsidiaries that left those corporations under various staff reduction programs from 1992 onward. These restriction apply when (a) such former employee(s) owns 10% or more of the shares of a company, or (b) such former employee(s) perform the contracted service, regardless of the manner of contracting (whether as an employee, consultant, contractor or otherwise).

(b) Accordingly, where 10% or more of a company is owned by such former employee(s), or where it is anticipated that such former employee(s) will be utilized in the performance of this contract, the Consultant shall identify the individual(s) involved and the details of their ownership or employment with the Consultant. The Consultant represents and warrants that this disclosure was correctly made in its Proposal or response to the Purchaser, and that the same is true as of the date of entering into this contract. This disclosure shall remain a continuing disclosure obligation of the Consultant during the performance of this contract.

34. **<u>Interpretation of Contract and Disputes</u>**

(a) This contract shall be governed by and interpreted in accordance with the laws of the Province of Ontario.

(b) The parties irrevocably submit to the exclusive jurisdiction of the courts of Ontario and the

Federal Court of Canada. All disputes in connection with this contract shall be commenced and heard in a court of competent jurisdiction in Toronto, Ontario.

35. **Laws, Regulations, and Codes**

The Consultant shall comply with all federal, provincial, and municipal statutes, regulations, bylaws, standards, and codes which are applicable to the Work.

End of A-29-2010 Document

School Energy Coalition Interrogatory # 21

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 2

Interrogatory:

Please explain why the benchmarking comparison is to an average performer, rather than to a superior performer or even a frontier performer. Please discuss from the expert's point of view the pros and cons of different benchmarking levels.

Response:

Basing the benchmark comparison on an "average" performer provides a more robust point of reference; one that is not as easily influenced by data anomalies and irregularities. Using "average" as the point of reference is also less subjective, as opposed to the researcher choosing an arbitrary "superior" level. If the research used a "frontier" definition, that frontier would be based on a small number of observations that define the frontier. Using a "frontier" definition would make benchmarking results dependent on a limited number of utilities and their performance, making the results less stable and trustworthy. Conversely, the "average" benchmark incorporated the entirety of the sample into the construction of the point of reference.

In conducting the research, PSE believes that it is the best practice to provide the comparisons using the more stable and robust point of reference—the average. It is then up to the regulatory process to determine how different levels of performance are defined in relation to the robust average. For example, in 4GIR, the different stretch factor groups define different performance levels.

School Energy Coalition Interrogatory # 22

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 5

Interrogatory:

Please quantify (or estimate) the impact on the study of:

a) Excluding contributions in aid of construction;

b) Adding high voltage costs;

c) Adding bad debt expenses;

d) Adding embedded distribution demand to maximum peak demand.

Response:

PSE estimated the impacts of the 4 items by either adding the costs back into Hydro One (in the case of the contributions in aid of construction) or subtracting the item from Hydro One (in the case of the other 3 items). For comparison, PSE used the last historical year of the Hydro One results, 2016. In 2016, we found that Hydro One's costs are 21.6% above the benchmark costs. If we change each item individually, the 2016 benchmark changes by the following values:

Requested Sensitivity Test	Change in 2016 Benchmark Score with Requested Change Made	2016 Benchmark Score with Requested Change Made
Excluding CIAC	0.0%	+21.6%
Adding high voltage	-1.8%	+19.8%
Adding bad debt	-0.4%	+21.2%
Adding embedded distribution demand	-0.2%	+21.4%
No Changes Made	0.0%	+21.6%

Witness: PSE

School Energy Coalition Interrogatory # 23

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 6

Interrogatory:

Please explain how the model deals with the interchangeability of labour and non-labour (outsourcing) costs and makes the comparison reasonable.

Response:

The model uses the same assumption that was used in the 4GIR total cost benchmarking research: 70% for labour (OM&A expenses), and 30% for non-labour expenses. This assumption is not impacted by how individual distributors may interchange labour and non-labour through outsourcing.

School Energy Coalition Interrogatory # 24

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 13

Interrogatory:

Please quantify the figure of 0.811% as a dollar figure per new customer, and quantify the figure of 0.097% as a dollar figure per MW of increased peak demand.

Response:

To determine a dollar figure per new customer, PSE performed the following steps:

- Added 1,000 customers to Hydro One's 2016 variable value,
- Calculated the difference in the total cost benchmark from the original due to the adding of 1,000 customers, and
- Divided that difference by 1,000 to get a per customer estimate.

We added 1,000 to avoid the results being influenced significantly by rounding.

For the MW request, we added 1 MW to Hydro One's 2016 variable value, and then calculated the difference in the original total cost benchmark and the benchmark with the hypothetical increase of 1 MW in the maximum peak demand.

PSE found that the total cost benchmark for Hydro One increased by $1,026 in 2016 if the number of customers for Hydro One increased by one in 2016. The total cost benchmark for Hydro One increased by $392 if the maximum peak demand for Hydro One increased by 1 MW in 2016.

School Energy Coalition Interrogatory # 25

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01

Interrogatory:

With respect to the Navigant Distribution Unit Cost Benchmarking Study (General Questions):

a) [p.5] Please explain why Navigant did not reach out to additional Ontario LDCs, to take part in the study after it only obtained cooperation from three of its original list of utilities to target for participation.

b) [p.7] Please provide a copy of the questionnaire provided to all participating LDCs.

c) Please provide a copy, in excel format, of all data received from participating LDCs. (With the exception of data from Hydro One, SEC does not object to the information being anonymized).

d) [p.27] For Hydro One: Please provide Hydro One's response to the recommendations.

Response:

a) In addition to the Ontario LDCs that did agree to take part in the study, Navigant and First Quartile reached out to the following Ontario LDCs that chose not to participate in the study:

   1. Greater Sudbury Ontario
   2. Algoma Power
   3. Entegrus Powerlines

b) A copy of the questionnaire is attached to this response.

c) Data transmitted by companies other than Hydro One was provided to Navigant and First Quartile under strict confidentiality requirements. To obtain the data, Navigant and First

Quartile are required to anonymize individual company results and disclose only summary metrics.

d) Please see response to Exhibit I-25-Staff-126.

FIRST QUARTILE CONSULTING

DISTRIBUTION SUBSTATION REFURBISHMENT INFORMATION

Please provide contact information for this section.

Company	
Name	
Telephone	
e-mail	

Be sure to review the glossary.

Guidelines

The reported substation counts should include only company-owned distribution substations as defined in the Glossary

Data Entry rules:

1] Enter percents as whole numbers. 2% = 2, 0.05% = 0.05, but do not include % sign
2] Do not enter %, $ or other signs with numeric data. This will cause data to be treated as text and cause it to graph incorrectly
3] Do not enter "," as a separator in large numeric values
4] Please be brief and to-the-point on text answers.

A. DISTRIBUTION SUBSTATION DEMOGRAPHICS

A1 How many distribution substations do you currently have in service? Enter the number of substations that fit into each category by Row/Column (eg. 5 substations are rural with 1 transformer).

	1 Xfrmr stations	2 Xfrmr stations	3 Xfrmr stations	4 or more Xfrmr stations
Rural				
Mixed/Suburban				
Urban				
Not Classified				

A2 What is the current count of installed distribution substation power transformers (3-phase banks) by high side and low side voltage?

High Side: / Low Side:	>1kV to 5kV	5kV to 9.9kV	10kV to 14.9kV	15kV to 19.9kV	20kV to 29.9kV	30kV to 45.9kV
less than 15kV						
15kV to 29.9kV						
30kV to 49.9kV						
50kV to 99.9kV						
100kV to 199.9kV						
200Kv or higher						

A3 What percent of your current in-service distribution substation equipment components were manufactured in each time period?

Data in each row should total to 100%

	Before 1960	1960's	1970's	1980's	1990's	Since 2000	Unknown	Total	
Power Transformers								0	%
High Side Breakers / Switch Fuse Units/ Bus-ties								0	%
Low Side Breakers / Reclosers / Bus-ties								0	%
Relays and Control Wiring								0	%
Switch Gear Control Panels								0	%
DC Components								0	%
Metering								0	%

A4 What is your expected service life of distribution substation equipment components?

Power Transformers		Years
High Side Breakers/Switch Fuse Units/Bus-ties		Years
Low Side Breakers/Reclosers/Bus-ties		Years
Relays and Control Wiring		Years
Switch Gear Control Panels		Years
DC Components		Years
Metering		Years

A5 What was the average transformer loading at peak percent for your distribution substation power transformers over the past 12 months?

Average Power Transformer Loading at Peak		%

B. DISTRIBUTION SUBSTATION REFURBISHMENT PROGRAM INFORMATION

B1 Under what criteria do you complete distribution substation refurbishment work under an "Individual Component-Focused Approach", a "Station-Centric Approach", a "Full Station Rebuild Approach" or some "Other Approach"?

Individual Component-Focused	
Station-Centric	
Full Station Rebuild	
Other Approach Used	

B2 How many distribution substation refurbishments have been completed and are planned for completion?

	2010 through 2014	2015 through 2019
Individual Component-Focused		
Station-Centric		
Full Station Rebuild		
Other Refurbishment Approach		

B3a Has any proposed distribution substation refurbishment program funding been disallowed by your regulator?

☐ Yes
☐ No

B3b If yes, what was the reason for funding being disallowed by regulator?

B4 What evaluations of individual substation components are performed to determine the need for a refurbishment project at an existing distribution substation?

Check all that apply

	Visual Inspection	Testing	Current / Forecasted Loading	Mntce History & Costs	Environ-mental Risk Analysis	Other
Power Transformers	o	o	o	o	o	o
High Side Breakers / Switch Fuse Units/ Bus-ties	o	o	o	o	o	o
Low Side Breakers /Reclosers / Bus-ties	o	o	o	o	o	o
Switchgear	o	o	o	o	o	o
Relays and Control Wiring	o	o	o	o	o	o
Bus Structures	o	o	o	o	o	o
DC Components	o	o	o	o	o	o
Metering	o	o	o	o	o	o
Foundations and Supporting Soil	o	o	o	o	o	o
Building Structures	o	o	o	o	o	o
Grounding Grid	o	o	o	o	o	o
Fencing	o	o	o	o	o	o
Security Equipment	o	o	o	o	o	o

B5 Please describe any substation component evaluations that you classified as "Other" in question 4.

Power Transformers	
High Side Breakers / Switch Fuse Units/ Bus-ties	
Low Side Breakers / Reclosers / Bus-ties	
Switchgear	
Relays and Control Wiring	
Bus Structures	
DC Components	
Metering	
Foundations and Supporting Soil	
Building Structures	
Grounding Grid	
Fencing	
Security Equipment	
Other Components	

B6 For any equipment components that are evaluated based on testing (as identified in your response in question 4), please list the specific tests that are performed:

Power Transformers	
High Side Breakers / Switch Fuse Units/ Bus-ties	
Low Side Breakers / Reclosers / Bus-ties	
Switchgear	
Relays and Control Wiring	
Bus Structures	
DC Components	
Metering	
Foundations and Supporting Soil	
Building Structures	
Grounding Grid	
Fencing	
Security Equipment	
Other Components	

B7a For each component that is evaluated (as identified in question 4), what are the specific asset condition criteria that will cause that component to be replaced vs. rebuilt/reconditioned during a distribution substation refurbishment project?

	Replacement Criteria
Power Transformers	
High Side Breakers / Switch Fuse Units/ Bus-ties	
Low Side Breakers / Reclosers / Bus-ties	
Switchgear	
Relays and Control Wiring	
Bus Structures	
DC Components	
Metering	
Foundations and Supporting Soil	
Building Structures	
Grounding Grid	
Fencing	
Security Equipment	
Other Components	

B7b For each component that is evaluated (as identified in question 4), what are the specific asset condition criteria that will cause that component to be rebuilt/reconditioned vs. replaced during a distribution substation refurbishment project?

	Rebuilt/Reconditioned Criteria
Power Transformers	
High Side Breakers / Switch Fuse Units/ Bus-ties	
Low Side Breakers / Reclosers / Bus-ties	
Switchgear	
Relays and Control Wiring	
Bus Structures	
DC Components	
Metering	
Foundations and Supporting Soil	
Building Structures	
Grounding Grid	
Fencing	
Security Equipment	
Other Components	

B8a Do you use “integrated modules” (multiple substation components mounted on a single platform) in any of your distribution substation refurbishment projects?

- [ ] Yes
- [ ] No

B8b If yes, please describe the standard integrated module design(s) that you use.

B9 When performing refurbishment work at single transformer distribution substations, how do you maintain electric service to customers while the transformer and/or high-side breaker are being replaced or rebuilt/reconditioned?

- [ ] Transfer all load to adjacent stations through line switching
- [ ] Transfer load to a mobile substation unit
- [ ] Install a mobile/spare transformer
- [ ] Other method

Please explain "other" in the question above.

DISTRIBUTION SUBSTATION REFURBISHMENT PROJECTS

Please provide contact information for this section.

Company	
Name	
Telephone	
e-mail	

Be sure to review the glossary.

Guidelines

1) In questions C2 and C2a, we are seeking basic information on substation refurbishment work that was completed since 1/1/2010 at up to three of your distribution substations. If you refurbished more than three substations since 1/1/2010, please select the three substations where you completed the largest amount of refurbishment work. **This is essential information for the study. Please answer questions C2 and C2a even if you are not able to provide the more detailed project information that is requested in questions C3 through C8. Also, please furnish the "Total Station Refurbishment Cost" in question C2a even of you are not able to furnish the "Associated Costs" fof the major work components.**

2) In questions C3 through C8, we are seeking more detailed cost breakdowns and project scope information for each **separate project** that was completed since 1/1/2010 at each of the stations identified in C2. There are a total of five project rows to accomodate companies that may have completed multiple refurbishment projects at a particular station. Use as many pf those rows as you need to describe each separate refurbisment project that was completed at the station since 1/1/2010

3) Question C3 asks that company labor cost data be split into two components: “direct labor costs” and “direct labor overheads” Questions C4 and C5 ask for percentage breakdowns of the direct labor costs and direct labor overheads. All of the associated terms are defined in the Glossary. Please review the glossary definitions before developing your responses.

Data Entry rules:

1] Enter percents as whole numbers. 2% = 2, 0.05% = 0.05, but do not include % sign
2] Do not enter %, $ or other signs with numeric data. This will cause data to be treated as text and cause it to graph incorrectly
3] Do not enter "," as a separator in large numeric values
4] Please be brief and to-the-point on text answers.

C1 Please indicate if you are answering in Canadian or US dollars.

See Guidelines for how to complete this section CAD USD

C2 Please provide the following information for ~~the~~ three stations that underwent refurbishment since 1/1/2010 and for which you'll be providing ~~project~~ work scope and cost information.

	Station Name	Rural, Suburban, or Urban	# of Power Xfrmrs	Station High Side Voltage (kW)	Station Low Side Voltage (kW)	Station Total MVA
Station #1						
Station #2						
Station #3						

C2a For each of the stations identified in question C2, please provide the following high-level work scope and cost information about all refurbishment work that was completed at the station since 1/1/2010 (could have been accomplished through one project or multiple projects):

Notes:

1. *In the "Refurbishment Approach" column, enter CF if the refurbishment work at the station was completed predominantly through Individual Component-Focused project(s), SC if it was completed predominantly through a single Station-Centric project, FS if it was completed predominantly through a Full Station Rebuild project or OT if is was completed through some other project approach (see Glossary for definitions for the first three terms)*

2. *Enter the numbers and rated capacities of the major equipment components that were installed during the refurbishment project(s), either to replace existing units or to provide additional/spare capacity. For the High Side Breaker/Switch Fuse Unit and Low Side Breaker/Recloser components, also enter a description of the type of equipment that was installed such as "SF6 gas CB", "High Voltage Switch-Fuse Unit", "Vacuum Recloser", "Oil CB", etc.* ***This information about the numbers, rated capacities and types of equipment that was installed during the refurbishment process is very important to this study. Please furnish this information even of you are not able to provide the "Associated Costs"***

3. *The "Associated Costs" reported for each component should include associated engineering/design costs, the purchase cost of the equipment and the cost of all company or contract labor and vehicles/construction equipment used to transport the equipment to the job site, install it at its final location and connect it to other equipment at the station. Also include the cost of company or contract labor used to perform start-up testing/commissioning tasks prior to placing the equipment in service.*

4. *The "Associated Costs" reported in the four yellow columns should sum up to the "Total Substation Refurbishment Costs" reported in the pink column. However,* ***if you are not able to estimate the Associated Costs, you may leave the yellow columns blank but should still report the Total Substation Refurbishment Costs in the pink column.***

		Power Transformers			High Side Breakers or Switch Fuse Units				Low Side Breakers or Reclosers				All Other Components Combined				
	Refurbishment Approach Used (Enter either CF, SC, FS or OT)	# Units Installed	Rated Capacity of Units (MVA)	Associated Costs	# Units Installed	Rated Capacity of Units (kV and amps)	Unit Types/ Description	Associated Costs	# Units Installed	Rated Capacity of Units (kV and amps)	Unit Types/ Description	Associated Costs	Associated Costs	Total Station Refurbishment Costs (since 1/1/2010)	Year Wnen Majority of Work Was Performed	Used an Integrated Module? (Y/N)	Description of The Integrated Module That Was Used
Station #1																	
Station #2																	
Station #3																	

C3 For each of the stations identified in question C2, ~~P~~please provide the following information for each ~~substation~~ separate refurbishment project that was completed at the station since 1/1/2010

		Information			Engineering/Design Labor Costs			Construction Labor & Vehicle Costs				Commissioning Labor Costs					Hours/Outsourcing					
		Project Name	In Service Date (MM/YY)	Equipment and Material Costs	Company Direct Labor	Company Direct Labor Overheads	Contract Labor or Services	Company Direct Labor	Company Direct Labor Overheads	Contract Labor or Services	Vehicle and Equipment Cost	Company Direct Labor	Company Direct Labor Overheads	Contract Labor or Services	Other Project Costs	Total Project Cost	Company Engineering / Design Labor Hours	Engineering / Design - % Outsourced	Company Construction Labor Hours	Construction - % Outsourced	Company Commissioning Labor Hours	Commissioning- % Outsourced
Station #1	Project #1																					
	Project #2																					
	Project #3																					
	Project #4																					
	Project #5																					
Station #2	Project #1																					
	Project #2																					
	Project #3																					
	Project #4																					
	Project #5																					
Station #3	Project #1																					
	Project #2																					
	Project #3																					
	Project #4																					
	Project #5																					

C3a Please explain "other project costs" above.

C4 Please provide the following percent breakdowns of the Direct Labor costs that you reported above (overall percentages for all projects at each substation):

Columns in each table for each station should total to 100%.

		Company Engineering / Design Direct Labor	Company Construction Direct Labor	Company Commissioning Direct Labor
Station #1	Regular Staff Base Pay			
Station #1	Regular Staff Overtime			
Station #1	Non-Regular Staff Base Pay			
Station #1	Non-Regular Staff Overtime			
Station #1	Pension			
Station #1	Health & Welfare Benefits			
Station #1	Government Obigations			
Station #1	Other Direct Labor Costs			
Total	(should total to 100%)	0%	0%	0%
Station #2	Regular Staff Base Pay			
Station #2	Regular Staff Overtime			
Station #2	Non-Regular Staff Base Pay			
Station #2	Non-Regular Staff Overtime			
Station #2	Pension			
Station #2	Health & Welfare Benefits			
Station #2	Government Obigations			
Station #2	Other Direct Labor Costs			
Total	(should total to 100%)	0%	0%	0%
Station #3	Regular Staff Base Pay			
Station #3	Regular Staff Overtime			
Station #3	Non-Regular Staff Base Pay			
Station #3	Non-Regular Staff Overtime			
Station #3	Pension			
Station #3	Health & Welfare Benefits			
Station #3	Government Obigations			
Station #3	Other Direct Labor Costs			
Total	(should total to 100%)	0%	0%	0%

C5 Please provide the following percent breakdowns of the Direct Labor Overheads that you reported above (overall percentages for all projects at each substation):

Columns in each table for each station should total to 100%.

		Company Engineering / Design Direct Labor Overheads	Company Construction Direct Labor Overheads	Company Commissioning Direct Labor Overheads
Station #1	Supervisory Overheads			
Station #1	Administrative Support			
Station #1	Cost Allocations from Support Organizations			
Station #1	Other Overheads Applied to Direct Labor			
Station #1	(should total to 100%)	0%	0%	0%
Station #2	Supervisory Overheads			
Station #2	Administrative Support			
Station #2	Cost Allocations from Support Organizations			
Station #2	Other Overheads Applied to Direct Labor			
Station #1	(should total to 100%)	0%	0%	0%
Station #3	Supervisory Overheads			
Station #3	Administrative Support			
Station #3	Cost Allocations from Support Organizations			
Station #3	Other Overheads Applied to Direct Labor			
Station #1	(should total to 100%)	0%	0%	0%

C6 Please describe the intergrated moduled (if used) for each project.

		Use of Integrated Modules? Y/N	Description of Intergated Modules Used
Station #1	Project #1		
	Project #2		
	Project #3		
	Project #4		
	Project #5		
Station #2	Project #1		
	Project #2		
	Project #3		
	Project #4		
	Project #5		
Station #3	Project #1		
	Project #2		
	Project #3		
	Project #4		
	Project #5		

C7 ~~**Please indicate the project work scope for each project.**~~ **For each of the projects identified in question C3, please indicate the following detailed scope information:**

Enter 1 for Replaced, 2 for Rebuilt / Reconditioned, or 3 for Added or leave blank if nothing performed on that component.

		Power Transformers	High Side Breakers / Switch Fuse Units	Low Side Breakers/ Reclosers	Switchgear	Relays and Control Wiring	Bus Structures	DC Components	Metering	Foundations and Supporting Soil	Building Structures	Grounding Grid	Oil Containment Systems	Noise Abatement Structures	Fencing	Security Equipment
Station #1	Project #1															
	Project #2															
	Project #3															
	Project #4															
	Project #5															
Station #2	Project #1															
	Project #2															
	Project #3															
	Project #4															
	Project #5															
Station #3	Project #1															
	Project #2															
	Project #3															
	Project #4															
	Project #5															

C8 Please describe any other activity for each project: other components and whether they were replaced, rebuilt/reconditioned or added.

		Other components replaced, rebuilt/reconditioned, or added
Station #1	Project #1	
	Project #2	
	Project #3	
	Project #4	
	Project #5	
Station #2	Project #1	
	Project #2	
	Project #3	
	Project #4	
	Project #5	
Station #3	Project #1	
	Project #2	
	Project #3	
	Project #4	
	Project #5	

POLE

Please provide contact information for this section.

Company	
Name	
Telephone	
e-mail	

Be sure to review the glossary.

Guidelines

1) Pole counts should include all poles used to support overhead circuits and equipment that is energized at either a “secondary” or “distribution” voltage as defined in the Glossary.

2) We are asking that all company labor cost data collected in this survey be split into two components: “direct labor costs” and “direct labor overheads” These two components are defined in the glossary.

Data Entry rules:

1] Enter percents as whole numbers. 2% = 2, 0.05% = 0.05, but do not include % sign

2] Do not enter %, $ or other signs with numeric data. This will cause data to be

3] Do not enter "," as a separator in large numeric values

4] Please be brief and to-the-point on text answers.

D. DEMOGRAPHICS

D0 Please indicate if you are answering in miles or kilometers:

(●) Miles ( ) Kilometers

D1 How big is your service territory?

	Sq Kilometers/Miles
Service Territory Size	

D2 How many of your current in-service distribution and secondary poles were installed in each time period listed below?

Data for question should represent your total, current in-service pole population.

	Before 1960	1960's	1970's	1980's	1990's	Since 2000	Unknown	Total	
Wood								0	poles
Composite								0	poles
Concrete								0	poles
Steel								0	poles

D3 What percent of your in-service poles are installed in conditions described as:

Total should equal 100%

"Soft" meaning digging can be completed via normal excavation practices		%
"Rock" meaning digging must be conducted via specialized equipment (bore or mount)		%
"Swamp" meaning an area of low-lying land that is frequently flooded causing significant access issues		%
	0	%

D4 What does your company deem as end of service life (in years) for each pole type?

Wood		Years
Composite		Years
Concrete		Years
Steel		Years

D5 What are the drivers (in the last 3 years) for your recent pole work?

Total should equal 100%

Growth / Infrastructure improvements (road widening, new service)		%
Sustaining (age, reliability)		%
Other		%
	0	%

D6 **What is the accessibility of poles on your system described as a percentage?**

Total should equal 100%

On Road (accessible using on road equipment)		%
Off Road (accessible using off road equipment)		%
	0	%

D7 **As a percentage of your total pole population, how many poles support each of the following?**

Total should equal 100%

Single-phase circuits		%
Multi-phase circuits		%
	0	%

D8 **Please indicate how your pole replacement / refurbishment expenses are categorized the majority of time?**

Enter 1 for O&M or 2 for Capital, Leave blank if you do not do

Inspection process	
Dig The Hole	
Set The Pole	
Transfer The Equipment	
Truss/Stubbing	
Epoxy	
Wrap	
Retreatment Rods	
Other pole refurbishment activities	

D9 **Is there a regulation or policy that governs the manner in which you inspect, refurbish, and replace poles?**

- [ ] Yes
- [ ] No

D10 **What is the regulatory body and/or policy?**

D11 **What are the requirements for:**

Inspection cycle	
Record keeping	
Other	

E. INSPECTION PROCESS

E1 **Do you have an inspection process for your distribution poles?**

☐ Yes
☐ No

E2 **At what age do you start doing each of these types of inspections?**

99 = "As Needed"; Leave blank if you do not do.

		Urban	Non-urban	No difference	
Patrol	Age				Years
Visual	Age				Years
Sound	Age				Years
Bore	Age				Years
Excavation	Age				Years
Ultrasonic	Age				Years
Other	Age				Years

E3 **How often / what is your cycle time for doing each of these types of inspections?**

99 = "As Needed"; Leave blank if you do not do.

	Urban	Non-urban	No difference	
Patrol				Years
Visual				Years
Sound				Years
Bore				Years
Excavation				Years
Ultrasonic				Years
Other				Years

E4 **How many inspection cycles do you have archived?**

If you began a 10 year cycle in 1990 you would have 2 inspection cycles archived; if you began a 3 year cycle in 2010, you would have 1 cycle completed/archived. You would answer this question with "3".

Number of inspection cycles [ ]

E5 **What percent of pole inspections (climbing and ground) are performed by each group?**

Total should equal 100%

Company Labor		%
Contract Labor		%
Contract Services		%
	0	%

E6 **Please provide the information below for pole inspection activity.**

Inspection Results	# of Inspections Planned	# of Inspections Actually Completed
2012		
2013		
2014		

E7 **What have you spent on pole inspection activities over the past 3 years?**

	Company Direct Labor ($)	Company Direct Labor Overheads ($)	Equipment Cost ($)	Material Cost ($)	Contract Labor/ Services Cost ($)	Company Labor Hours
2012						
2013						
2014						
Breakdown Unavailable						

E7a **Please provide the following percent breakdown of the Direct Labor costs reported in the above question (overall percentages for 2012 to 2014 work):**

	Company Direct Labor- % Breakdown
Regular Staff Base Pay	
Regular Staff Overtime	
Non-Regular Staff Base Pay	
Non-Regular Staff	
Pension	
Health & Welfare Benefits	
Government Obigations	
Other Direct Labor Costs	
Total (should total to 100%)	0%

E7b **Please provide the following % breakdowns of the Direct Labor Overheads reported in the above question (overall percentages for 2012 to 2014 work):**

	Company Direct Labor- % Breakdown
Supervisory Overheads	
Administrative Support	
Cost Allocations from Support Organizations	
Other Overheads Applied to Direct Labor	
Total (should total to 100%)	0%

E8 Do you have a "pole refurbishment" practice?

- [ ] Yes
- [ ] No

E9 If yes, what types of refurbishment methods do you use?

- [ ] Truss / Stubbing
- [ ] Epoxy
- [ ] Wrap
- [ ] Retreatment Rods
- [ ] Other

Please explain "other" in above.

E10 Of the poles inspected, how many poles were found in each category? If unable to categorize based on year, record results in "Breakdown Not Available" row.

Enter the number of poles in each category each year.

Inspection Results	Serviceable (no work needed)	Serviceable and Preventative Refurbishment applied	Immediate Replacement Required	Requires replacement before the next inspection cycle	Requires refurbishment before the next inspection cycle
2012					
2013					
2014					
Breakdown Unavailable					

F. REPLACE OR REFURBISH PROCESS:

F0 **Please indicate if you are answering in Canadian or US dollars.**

○ CAD ○ USD

F1 **Typically how many months, post inspection, would you definitely complete all non-urgent inspection recommendations?**

If you don't have a plan to complete before your inspection cycle starts over, leave blank.

Months for completion ☐ Months

F2 **When taking action on the results of your inspections, do you replace or refurbish based**

☐ "All" – action is taken across the entire system?

☐ "Targeted" - action is limited or aimed at specific areas of the system (typically older, by circuit, by critical customers)?

☐ "Prioritized" - action is a part of a larger asset management program where spending is based on condition as well as the expected improvement of other business results (customer satisfaction, future costs, reliability, safety)?

F3 **How many poles did you replace or refurbish from 2012 to 2014? If unable to categorize based on year, record results in the "Breakdown Not Available" row.**

Work Completed	# of Poles Replaced	# of Poles Refurbished
2012		
2013		
2014		
Breakdown Unavailable		

F4 **What is the approximate average travel time for a company field crew to get to a pole that requires replacement or refurbishment?**

Average Travel Time (minutes) [ ]

F5 **When replacing joint use poles, do you have agreements in place with telephone and/or CATV utilities that allow/require them to remove the old pole after they transfer their facilities to the new electric utility-owned joint use pole?**

- [ ] Yes
- [ ] No

F6 **What have you spent on pole replacement in the past 3 years?**

	Company Direct Labor ($)	Company Direct Labor Overheads ($)	Equipment Cost ($)	Material Cost ($)	Contract Labor/ Services Cost ($)	Company Labor Hours
2012						
2013						
2014						
Breakdown Unavailable						

F6a Please provide the following percent breakdown of the Direct Labor costs reported in the above question (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Regular Staff Base Pay	
Regular Staff Overtime	
Non-Regular Staff Base Pay	
Non-Regular Staff	
Pension	
Health & Welfare Benefits	
Government Obigations	
Other Direct Labor Costs	
Total (should total to 100%)	0%

F6b Please provide the following % breakdowns of the Direct Labor Overheads reported in the above question (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Supervisory Overheads	
Administrative Support	
Cost Allocations from Support Organizations	
Other Overheads Applied to Direct Labor	
Total (should total to 100%)	0%

F7 What have you spent on pole refurbishment in the past 3 years?

	Company Direct Labor ($)	Company Direct Labor Overheads ($)	Equipment Cost ($)	Material Cost ($)	Contract Labor/ Services Cost ($)	Company Labor Hours
2012						
2013						
2014						
Breakdown Unavailable						

F7a Please provide the following percent breakdown of the Direct Labor costs reported in the above question (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Regular Staff Base Pay	
Regular Staff Overtime	
Non-Regular Staff Base Pay	
Non-Regular Staff	
Pension	
Health & Welfare Benefits	
Government Obigations	
Other Direct Labor Costs	
Total (should total to 100%)	0%

F7b Please provide the following % breakdowns of the Direct Labor Overheads reported in the above question (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Supervisory Overheads	
Administrative Support	
Cost Allocations from Support Organizations	
Other Overheads Applied to Direct Labor	
Total (should total to 100%)	0%

F8 How many poles and what have you spent on Emergency pole replacement in the past 3 years?

	Company Direct Labor ($)	Company Direct Labor Overheads ($)	Equipment Cost ($)	Material Cost ($)	Contract Labor/ Services Cost ($)	Company Labor Hours	# Of Poles Emergency Replacement
2012							
2013							
2014							
Breakdown Unavailable							

F8a Please provide the following percent breakdown of the Direct Labor spending reported in the above question? (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Regular Staff Base Pay	
Regular Staff Overtime	
Non-Regular Staff Base Pay	
Non-Regular Staff	
Pension	
Health & Welfare Benefits	
Government Obigations	
Other Direct Labor Costs	
Total (should total to 100%)	0%

F8b Please provide the following % breakdowns of the Direct Labor Overheads reported in the above question? (overall percentages for 2012 to 2014 work)

	Company Direct Labor- % Breakdown
Supervisory Overheads	
Administrative Support	
Cost Allocations from Support Organizations	
Other Overheads Applied to Direct Labor	
Total (should total to 100%)	0%

F9 **How do you retain your past inspection and treatment/refurbishment data on in-service poles?**

- [ ] Store the information in files organized on a line or circuit basis
- [ ] Each in-service pole is searchable in a database
- [ ] Other

F9a **Explain "other" from above question.**

F10 **Do you retain past inspection and treatment/refurbishment data on poles that were replaced?**

- [ ] Yes
- [ ] No

F10a **If yes, what specific data is retained and how long is that data retained after the pole was replaced?.**

FIRST QUARTILE CONSULTING

POLE REPLACEMENT

Please provide contact information for this section.

Company	
Name	
Telephone	
e-mail	

Be sure to review the glossary.

Data Entry rules:

1] Enter percents as whole numbers. 2% = 2, 0.05% = 0.05, but do not include % sign

2] Do not enter %, $ or other signs with numeric data. This will cause data to be treated

3] Do not enter "," as a separator in large numeric values

4] Please be brief and to-the-point on text answers.

G. POLE REPLACEMENT PROCESS

To better understand your people / resource / equipment / materials, please fill in the tables below for each of the different scenarios. For these tables include the following activities: dig hole, set pole, transfer of all electrical equipment.

G1 Scenario 1: Along a roadside, in soft soil, set a 30'-50' class 1 or 2 pole, transfer, single-phase primary and secondaries from old pole to new pole. (not including removal of the pole)

	Activity Performed	Number of people needed	Person hours needed	Number of bucket trucks need	Number of digger derricks need	Number of pick-up trucks need	List any additional equipment needed
Trip 1							
Trip 2							
Trip 3							
Trip 4							
Trip 5							
Trip 6							
Trip 7							

G2 Scenario 2: Along a roadside, in soft soil, set a 30'-50' class 1 or 2 pole, transfer, three-phase primary and secondaries from old pole to new pole. (not including removal of

	Activity Performed	Number of people needed	Person hours needed	Number of bucket trucks need	Number of digger derricks need	Number of pick-up trucks need	List any additional equipment needed
Trip 1							
Trip 2							
Trip 3							
Trip 4							
Trip 5							
Trip 6							
Trip 7							

G3 Scenario 3: Along a roadside, in rock, set a 30’-50’ class 1 or 2 pole, transfer, single-phase primary and secondaries junction pole from old pole to new pole. (not including removal of the pole)

	Activity Performed	Number of people needed	Person hours needed	Number of bucket trucks need	Number of digger derricks need	Number of pick-up trucks need	List any additional equipment needed
Trip 1							
Trip 2							
Trip 3							
Trip 4							
Trip 5							
Trip 6							
Trip 7							

G4 Scenario 4: Along a roadside, in rock, set a 30’-50’ class 1 or 2 pole, transfer, three-phase primary, three-phase transformer and secondaries from old pole to new pole. (not including removal of the pole)

	Activity Performed	Number of people needed	Person hours needed	Number of bucket trucks need	Number of digger derricks need	Number of pick-up trucks need	List any additional equipment needed
Trip 1							
Trip 2							
Trip 3							
Trip 4							
Trip 5							
Trip 6							
Trip 7							

School Energy Coalition Interrogatory # 26

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
B1-01-01 Section 1.6-A01

Interrogatory:
With respect to the Navigant Distribution Unit Cost Benchmarking Study (Pole Replacement Benchmarking):

a. [p.8, 15] Please provide individual figures similar to Figure 8 (Pole Program Costs Ranked by Annual Spend) and Figure 18 (Pole Replacement Cost Ranked by Annual Spend) for each of 2012, 2013 and 2014.

b. Please provide the information requested in part (a), in a table format.

c. [p.15] On the same basis as the information Hydro One provided to Navigant for 2012-2014 (for example, as shown in Figure 18), please provide its actual Costs Per Pole Replaced for 2015 and 2016, and its forecast for each year between 2017 and 2022.

d. [p.13] Is the information provided by Hydro One and participating LDCs of pole replacement data, only for dedicated pole replacement programs, or does it also include poles replaced in the context of other distribution capital programs?

Response:
a) Results from Figure 8 are provided below:

Figure 8. Pole Program Costs Ranked by Annual Spend

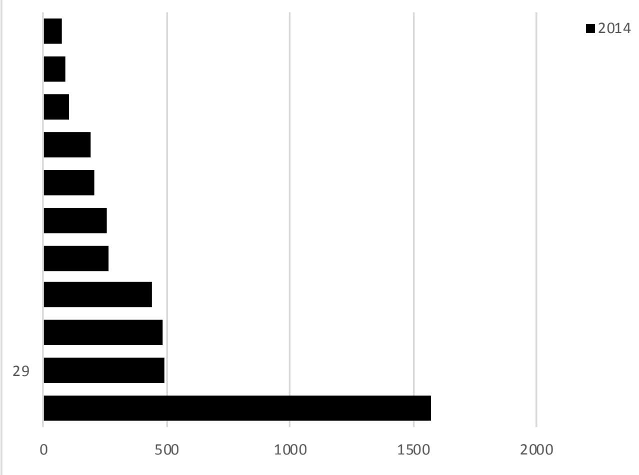


Figure 8. Pole Program Costs Ranked by Annual Spend

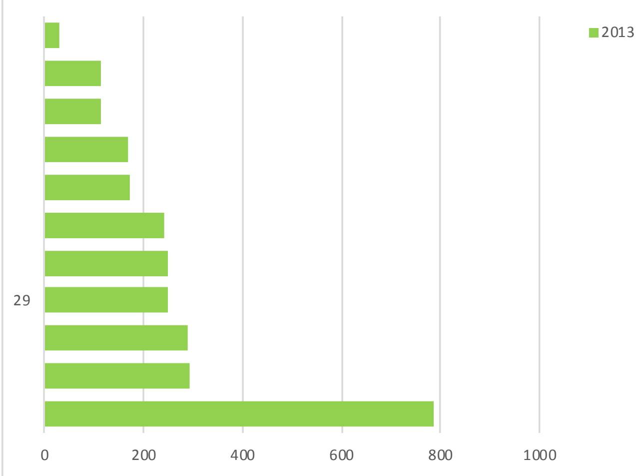
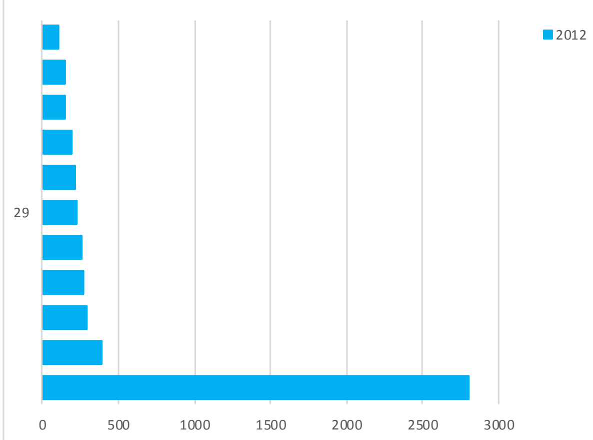


Figure 8. Pole Program Costs Ranked by Annual Spend



Results from Figure 18 are provided here:

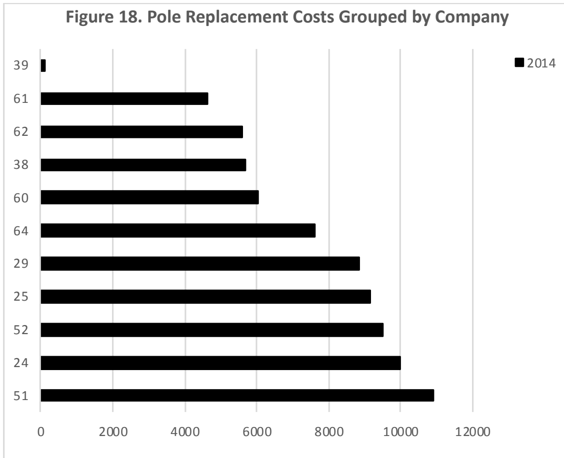


Figure 18. Pole Replacement Costs Grouped by Company

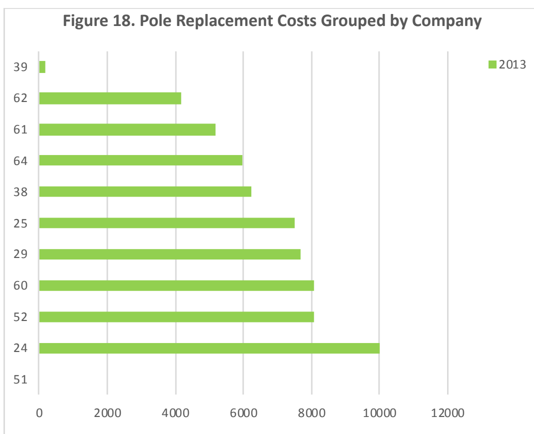
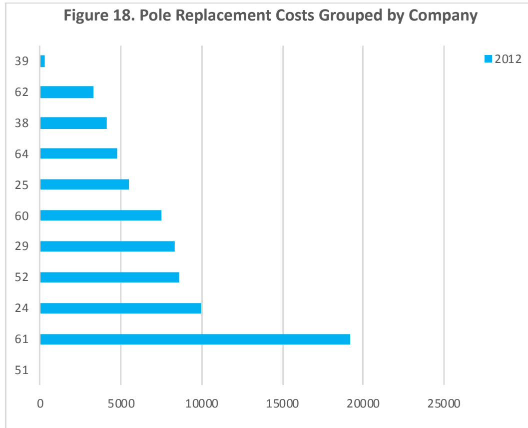


Figure 18. Pole Replacement Costs Grouped by Company

Witness: Navigant



b) The information in table format is provided below.

Figure 8 Data

	2014
	1574.76053
29	490.320961
	480.903811
	437.808671
	260.133684
	255.135124
	203.103224
	188.008439
	105.328377
	84.903435
	75.933646

	2013
	786.665637
	292.740203
	288.324122
29	248.678194
	247.051504
	240.984074
	173.769356
	169.058773
	114.777618
	112.905571
	29.814815

	2012
	2803.60827
	393.772566
	289.587394
	266.112437
	260.396891
29	229.496601
	211.416343
	196.550212
	145.628028
	144.927536
	101.563335

Figure 18 Data

	2014
51	10905.1406
24	10004
52	9522.10047
25	9142.04594
29	8833.09276
64	7629.0132
60	6049.49007
38	5681.92847
62	5599.22857
61	4628.49485
39	95.53184

	2013
51	
24	10004
52	8095.08396
60	8061.59239
29	7670.20879
25	7514.375
38	6243.6664
64	5971.36
61	5184.87954
62	4179.13333
39	190.846911

	2012
51	
61	19153.0157
24	10004
52	8602.19576
29	8295.07746
60	7459.83175
25	5514.56831
64	4712.92235
38	4135.8227
62	3310.95
39	269.949663

c) Table 8 of Section 1.4 of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1) provides the historical pole replacement unit cost for 2011-2016, as well as, the 2017 and 2018 forecasts. 2019-2022 forecast values can be found in Hydro One's response to Exhibit I-18-SEC-29.

d) The data includes those poles replaced on dedicated replacement programs, as well as others replaced in other situations. The majority of the pole replacements for all the companies are completed as part of the organized replacement programs.

School Energy Coalition Interrogatory # 27

Issue:
Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:
B1-01-01 Section 1.6-A01

Interrogatory:
With respect to the Navigant Distribution Unit Cost Benchmarking Study (Substation Refurbishment Benchmarking):

a. [p.17] Please define what Navigant considers i) full station rebuild projects, ii) substation-centric projects, and iii) component-based projects.

b. [p.17-26] How many utilities provided data for this part of the benchmarking study?

c. [p.17] Please explain why comparing costs on a per-MVA and transformer bank basis is appropriate.

d. [p.18-20] Please provide Figures 20-23 in a table format. Please also provide, for each type of transformer bank, how many are included in the benchmarking analysis.

e. Please provide the information requested in part (c) not normalized for MVA and number of transformer banks.

Response:
a) The following definitions were provided to the participating companies along with the questionnaire that collected data.

Full Station Rebuild: A refurbishment project at a specific substation is considered when certain critical components are determined to be in need of replacement. At that time, the entire substation is completely rebuilt on-site with all existing components being removed/demolished and replaced with new components.

Station Centric: A refurbishment project at a specific substation is considered when certain critical components are determined to be in need of replacement or major rebuild/reconditioning work. At that time, all of the other substation components are evaluated and a single, comprehensive substation refurbishment project is initiated to replace or rebuild/recondition all components of the substation that require attention.

Component-Based: Individual substation components are evaluated separately and any needed component replacement, rebuild or reconditioning work is completed through separate, component-focused refurbishment projects over a period of several years.

b) A total of 14 utilities (including Hydro One) provided at least some data for this part of the benchmarking study.

c) Over a span of years of conducting annual benchmarking studies, First Quartile has experimented with different normalizing factors for substation costs. The best cost predictor on an overall, long-term, basis is the level of invested capital (the asset base). That is followed by MVA of capacity and the number of transformer banks. In this case, where the analysis is about individual stations, and typically older ones being refurbished/replaced, the asset base might tend to give misleading results, so the MVA capacity and number of transformers were used to normalize the cost data.

d) The requested tables are provided below.

Fig 20	Cost/Bank Refurbished
18-2 FS 66/12 28MVA 1Trf Rural	5609873.816
61-1 FS 34.5/4.2 7MVA 1Trf Urban	3054011.138
61-3 FS 24.9/8.7 25MVA 4Trf Urban	2902102.663
29-1 FS 44/4.2 5MVA 1Trf Urban	2161254.73
64-2 FS 44/13.8 15MVA 1Trf Suburban	2040596.82
Fig 21	Cost/ MVA Refurbished
61-3 FS 24.9/8.7 25MVA 4Trf Urban	464336.4261
61-1 FS 34.5/4.2 7MVA 1Trf Urban	436287.3054
29-1 FS 44/4.2 5MVA 1Trf Urban	432250.946
18-2 FS 66/12 28MVA 1Trf Rural	200352.6363
64-2 FS 44/13.8 15MVA 1Trf Suburban	136039.788
Fig 22	Cost/Bank Refurbished
18-1 SC 66/12 14MVA 1Trf Rural	7427953.705
29-4 SC 44/4.2 7.5MVA 1Trf URBAN	4160000
18-3 SC 66/12 28MVA 1Trf Rural	3212675.818
29-6 SC 44/8.3 5MVA 1Trf Rural	2338000
29-3 SC 44/8.3 7.5MVA 1Trf Urban	2100538.19
40-3 SC 138/12.5 90MVA 3Trf Urban	1960312.005
40-1 SC 138/12.5 90MVA 3Trf Urban	1927647.876
40-2 SC 138/12.5 280MVA 3Trf Urban	1732528.236
61-2 SC 138/24.9 159MVA 2Trf Suburban	1725673.462
29-2 SC 27.2/8.3 5MVA 1Trf Suburban	1589814.39
64-1 SC 44/13.8 15MVA 1Trf Suburban	1414639.01
Fig 23	Cost/ MVA Refurbished
29-4 SC 44/4.2 7.5MVA 1Trf URBAN	554666.6667
18-1 SC 66/12 14MVA 1Trf Rural	530568.1218
29-6 SC 44/8.3 5MVA 1Trf Rural	467600
29-2 SC 27.2/8.3 5MVA 1Trf Suburban	317962.878
29-3 SC 44/8.3 7.5MVA 1Trf Urban	280071.7587
18-3 SC 66/12 28MVA 1Trf Rural	114738.4221
64-1 SC 44/13.8 15MVA 1Trf Suburban	94309.26733
40-3 SC 138/12.5 90MVA 3Trf Urban	65343.73351
40-1 SC 138/12.5 90MVA 3Trf Urban	64254.9292
61-2 SC 138/24.9 159MVA 2Trf Suburban	21706.58443
40-2 SC 138/12.5 280MVA 3Trf Urban	18562.80253

The number of transformer banks associated with each data point is indicated at the end of the description for each data point (e.g., the top data point on Figure 20 is for a single transformer suburban substation). The number of projects included in the benchmarking analysis by type and by number of transformer banks is tabulated in the table below

# Transformer Banks	Full Station Rebuild Projects (Figures 20 & 21)	Station Centric Projects (Figures 22 & 23)	Total Projects Included in the Analysis
One	4	7	11
Two		1	1
Three		3	3
Four	1	1	1
Total # Projects	5	11	16

e) Data transmitted by companies other than Hydro One was provided to Navigant and First Quartile was under strict confidentiality requirements. To obtain the data, Navigant and First Quartile are required to anonymize individual company results and disclose only summary metrics.

School Energy Coalition Interrogatory # 28

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A02

Interrogatory:

With respect to the CN Utility Consulting Hydro One Vegetation Management Study 2016:

a. [p.11] Please provide a copy of the 2009 study.
b. The individual peer group company codes each begin with either a letter Y, W, V, X or Z. Do these individual letters represent some classification? If so, please provide details.
c. [p.18-19] For each of Figure 2, 4, and 6, please include the median and average for a Canadian-only peer group.
d. [p.18] Please provide a similar Figure showing annual cost of UVM per kilometres of overhead Line cleared or brush controlled (Similar to the information Hydro One provided in its previous proceeding (see EB-2013-0416, PD1_Executive Panel Presentation, May 12 2014, p.9).
e. [p.55] On the same basis as provided in Table 5, please provide Hydro One's annual cost and annual kilometers completed forecast for each year between 2017 and 2022.
f. [EB-2013-0416, Undertaking 3.10, Attachment 1] In EB-2013-0416, Hydro One provided a copy of the Utility Benchmark Survey Analysis Preliminary Report: 2011-2012 Distribution CN Utility Benchmark Survey Analysis Preliminary Report. Has Hydro One participated in a more recent version of the study? If so, please provide the most recent version and identify the company code for Hydro One.

Response:

a) The requested report has been provided as Attachment 1 to this response.

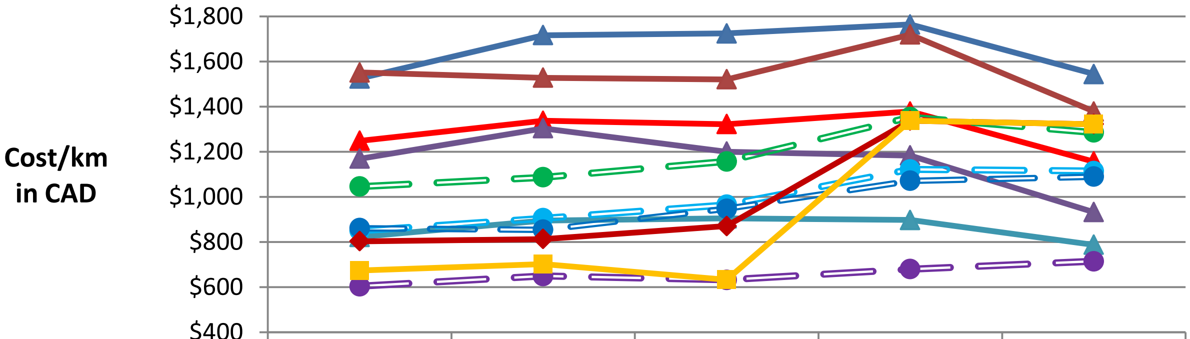
b) The codes are assigned randomly and new codes are assigned with each new survey performed by CNUC.

c) The requested updated Figures are provided below, where available.

Witness: BRADLEY Darlene, CN UTILITY

Total Cost for UVM per Overhead System Kilometres for 2011-2015

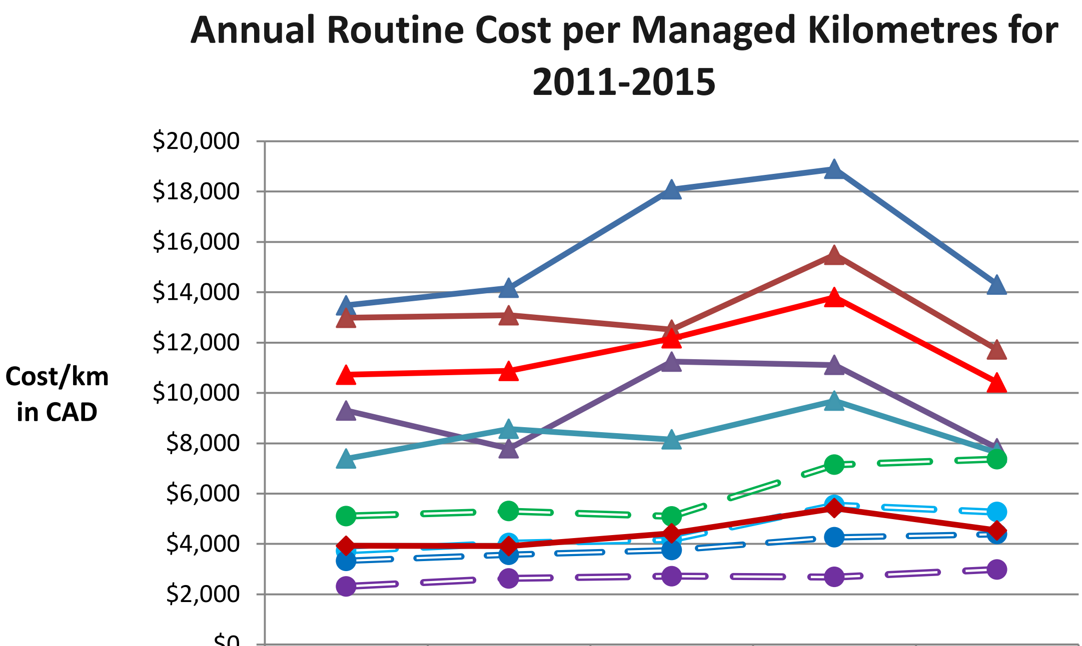
Total Cost Includes Routine, Reactive, Storm and New Construction Costs



	2011	2012	2013	2014	2015
HO Central	$1,525	$1,717	$1,725	$1,764	$1,544
HO East	$1,552	$1,528	$1,521	$1,720	$1,379
Hydro One	$1,248	$1,338	$1,323	$1,378	$1,157
HO North	$1,170	$1,304	$1,200	$1,183	$932
HO South	$822	$895	$904	$898	$788
Peer Average	$850	$905	$965	$1,122	$1,115
Peer Q1	$604	$649	$632	$680	$714
Peer Median	$862	$854	$947	$1,072	$1,090
Peer Q3	$1,046	$1,087	$1,157	$1,354	$1,286
CAN Peer AVG	$803	$813	$871	$1,338	$1,323
CAN Peer MED	$674	$703	$633	$1,338	$1,323

Figure 2

One Canadian company was excluded from the Canadian Peer Statistics since their program is mostly reactive work and would not be a good comparator in terms of cost.



	2011	2012	2013	2014	2015
HO Central	$13,483	$14,172	$18,084	$18,901	$14,303
HO East	$12,986	$13,087	$12,515	$15,487	$11,717
Hydro One	$10,721	$10,875	$12,163	$13,807	$10,417
HO North	$9,297	$7,795	$11,245	$11,112	$7,800
HO South	$7,388	$8,568	$8,150	$9,688	$7,624
Peer Average	$3,725	$4,034	$4,169	$5,547	$5,265
Peer Q1	$2,311	$2,633	$2,719	$2,688	$2,986
Peer Median	$3,326	$3,573	$3,756	$4,265	$4,391
Peer Q3	$5,107	$5,307	$5,092	$7,148	$7,370
CAN Peer AVG	$3,923	$3,912	$4,424	$5,418	$4,535

Figure 4

The CAN Peer Average and Median are the same for this metric

Cost Per Tree Treated (Figure 6)

There was an insufficient number of Canadian companies that supplied the necessary data to calculate this metric to offer peer averages and medians. It should be noted that utilities collect different sets of data on their VM program. Some metrics may not be a part of their dataset.

d) Please see response to Exhibit I-38-SEC-71.

e) The 2017 forecasted spend for vegetation management was $142.9 million and the actual units completed were 14,382 kilometers. As outlined on page 14 of Exhibit Q, Tab 1, Schedule 1, the unit forecast for 2018 to 2022 will be 34,666 kilometres annually and the forecasted budget for 2018 is $149.6 million. Hydro One expects to manage over the Custom IR term within the 2018 budget as adjusted by the proposed Revenue Cap Index described in Exhibit A, Tab 3, Schedule 2.

f) The final version of the 2011-2012 Cumulative Distribution CN Benchmark Survey Report was filed in EB-2013-0416 and is provided as Attachment 2 to this response. In this report Hydro One is utility 12, Hydro One's southern zone is utility 72, the northern zone is utility 73 and the eastern zone is utility 74. Since this report, Hydro One has participated in the CNUC benchmarking study filed in Exhibit B1-1-1, Section 1.6 Attachment 2.

HYDRO ONE 2009 – VEGETATION MANAGEMENT BENCHMARKING STUDY

ANALYSIS AND REPORT

September 18, 2009

Prepared by:

CN Utility Consulting, Inc
120 Pleasant Hill Ave. North
Suite 190
Sebastopol, CA 95472

TABLE OF CONTENTS

1. Executive Summary

Study Purpose

The purpose of the study is to provide definitive information related to Hydro One's Utility Vegetation Management (UVM). The core of the study was a benchmarking effort involving a group of 14 comparable utilities along with Hydro One and its 3 Forestry Zones. This group represents companies that are comparable based on vegetion density, weather and storm patterns, and rural service territory.

Key Study Findings

Efficiency & Productivity Summary

1. Hydro One and its zones have better than average efficiency in labour hours for line clearing and brush control activities.
2. Hydro One and its zones currently have greater than average costs per kilometre and per tree but when normalized for the great vegetation densities are performing close to average efficiency.
3. Hydro One and its zones have better than average efficiency in terms of both labour hours and costs associated with customer notification and job planning.
4. Hydro One and its zones have worse than average efficiency in the area of unplanned UVM activity.
5. Hydro One's performance is slightly better than average cost when total UVM expenditures are examined on the basis of total system kilometers.

Operational Attributes Summary

1. Hydro One has the longest average reported cycle length in the study at 10 years as most participants operate on a 3 to 5 year cycle. The length of the cycle is on the fringe of acceptable UVM practice and leads to inefficiencies as a result of excessive vegetation growth between successive maintenance.
2. Hydro One has one of the more densely vegetated service territories when measured using the number of trees treated per kilometre and naturally has a greater workload than the average peer utility.
3. Hydro One has a best in class safety record that is evidence of a well managed UVM program. A zero incident rate is the goal of every company, crew and worker, but to attain it requires training and the adoption of safe work practices that can impact the labour hours and costs to conduct work.

4. Hydro One is plagued by a high degree of tree caused unreliability, which is not unexpected given its densely vegetated service territory and the severity of the weather and storms across its territory. However, this is a sign of a system that can substantially improve the control of its vegetation.

INNOVATIONS IMPROVING PRODUCTIVITY AND EFFICIENCY

As part of this benchmarking study and consistent with the OEB's direction for Hydro One "to give effect to any innovations which improve its productivity and efficiency", CNUC also inquired about recent innovations that Hydro One has put in place in the UVM area. These inquiries identified a number of innovations including the piloting of mini-grinders for brush control, the increased emphasis on herbicide application, the development of lighter weight pruners for line clearing, and the usage of technology such as tablet computers and information technology in the area of customer notification and job planning. CNUC considers these innovations to be evidence of a prudent focus on efficiency and industry leading best practices.

CONCLUSION

Hydro One's relative efficiency performance has been challenged by a long maintenance cycle that allows for significant amounts of vegetation growth on rights of way and by challenging service territory characteristics. These characteristics include the most rural system of any participating utility in this study and a densely vegetated geography that naturally increases UVM workload. Despite these challenges, Hydro One's efficiency in a number of areas is comparable and in some cases leading the utilities in the study. In areas where efficiency does lag, the driving forces are explained by the aforementioned challenges. CNUC expects that if Hydro One is successful in reducing its cycle length in a controlled manner and can sustain accomplishment levels associated with lower cycles, then the company's UVM efficiency will be improved along with system reliability.

2. Introduction

2.1 Study Background

Hydro One is submitting a Distribution Rate Application in 2009 to its regulator, the Ontario Energy Board (OEB) to adjust rates for the 2010 and 2011 periods. As part of the previous (2008) rate decision, the OEB instructed Hydro One to develop a benchmarking approach that will provide definitive information respecting the company's relative efficiency in the area of vegetation management. The specific excerpt from that rate decision is as follows:

> *"Accordingly, the Board will require the Company, in consultation with the interveners and Board staff, to develop a benchmarking approach which will provide the Board at the next rebasing exercise with definitive information respecting the Company's relative efficiency in this area of operations. In the interim, the Board will expect the Company to give effect to any innovations which improve its productivity and efficiency in this area."*

On Wednesday April 15th, 2009, Hydro One held a stakeholder session with interveners and Board staff to solicit input. Based on the input received at that session, a benchmarking approach was developed and CN Utility Consulting (CNUC) was engaged to execute the benchmarking study. This report summarizes the execution of the study along with its findings and conclusions.

2.2 The Study Team - CN Utility Consulting (CNUC)[1]

CNUC was selected as an independent third party consulting team to execute Hydro One's Vegetation Management Benchmarking Study as a result of its expertise in both Utility Vegetation Management (UVM) and in benchmarking. This combination of expertise is unique in North America and is evidenced by experiences and achievements that CNUC brings as a consulting team. Details of CNUC's experiences and achievements can be found in Appendix A of this report.

2.3 Goals & Objectives of the Benchmarking Study

CNUC's first step was to review the input gathered at the stakeholder session and combine it with the direction provided by the OEB in its previous rate decision. Based on that review, the primary purpose of this benchmarking study is to capture measurements of UVM efficiency for Hydro One and its peer utilities in order to:

1) Compare Hydro One to its peers;
2) Compare subsets of Hydro One to peer utilities;

The core of the study will need to be a confidential solicitation of information from utilities in North America to discover relative efficiencies. Based on stakeholder input, CNUC identified the following considerations that were used to help guide the benchmarking study:

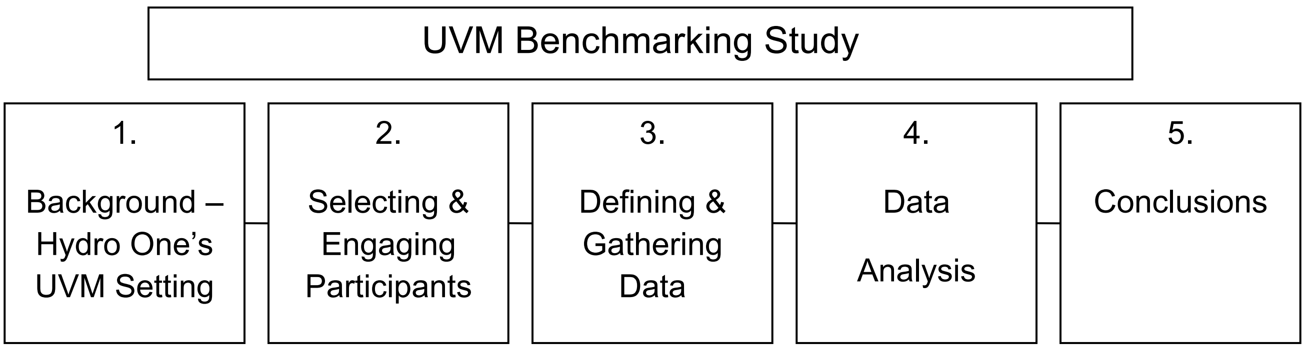
- Relative efficiency includes both labour and cost efficiency;

[1] A comprehensive listing of experiences and achievements is contained in Appendix A

- Cost is directly related to other measurements such as system characteristics, operational conditions and practices, reliability, and safety;
- Cost should be related to other parameters such as kilometres and total OM&A costs;
- Comparability characteristics should be considered when choosing participants.
- Comparability criteria must be explicitly identified using defined measures;
- Comparison criteria suggested:
    1. Percentage of lines requiring vegetation management;
    2. Type of terrain comprising the service territory;
    3. Differentiations between rural and urban territories;
    4. System characteristics such as splits between on-road and off-road lines and overhead and underground lines.
- Several years should be averaged to even out fluctuations and anomalies;
- Hydro One should be compared as a whole company and as separate, stand alone zones.

3. Benchmarking Study Framework

In consideration of the study purpose, objectives, and guidance provided by the stakeholders, CNUC developed a framework that was followed for this study. A summary of the framework is illustrated below, details for which are contained in Appendix B. The remainder of this report summarizes how CNUC progressed through each stage of the framework and documents the findings along the way.



3.1 Background - Hydro One's UVM Setting

A clear understanding of the nature of Utility Vegetation Management (UVM) in Ontario along the more than 100,000 kilometres of distribution primary lines worked on by Hydro One's utility arborists is critical to the success of the benchmarking study. This section of the report summarizes the necessary background information that CNUC gathered. Additional details and a number of useful maps and illustrations are contained in Appendix C.

3.1.1 Vegetation & Service Territory

The service territory of Hydro One is approximately 650 thousand square kilometres, and comprises most of Ontario which is about the size of California and Texas combined. Aside from a number of urban centres (e.g. Toronto, Ottawa, London), the majority of which are not served by Hydro One's distribution operations, the Province of Ontario is characterized by rural and remote areas. These areas are typically covered by a variety of forests as illustrated in the map contained in Section C1 of Appendix C. The north is coniferous forest, while the central is mixed forest transitioning to broadleaf forest. The far south of the Province contains more grassland and cropland. The highest concentrations of trees in Ontario appear to exist in the section of the Boreal Shield, north of Lake Superior and in the areas north and north-east of Lake Huron.

To manage the vast and diverse territory, Hydro One's UVM operations are divided into three zones. As is subsequently shown in this report and the introductory charts in Appendix E, the Southern Zone has the most circuit kilometres, the most customers and the smallest service territory. The Northern Zone has the least circuit kilometres, the largest service territory, and the least number of customers. The Eastern Zone fits in the middle of these measurements but it has a slightly higher customer density than the other two zones. The zones are illustrated in the Hydro One Forestry Zone Map in Appendix E.

3.1.2 Weather & Storm Events

Given the vast territory, each of the zones experience different weather and storm patterns and as a result, different vegetation growing conditions and threats. Growing conditions are predominantly driven by precipitation and temperature. The conditions are most favourable in the south where rainfall is the greatest and temperatures are generally milder. The central part of the province also sees a significant amount of rainfall, especially off of the coast of Georgian Bay, but has a slightly shorter growing season given its slightly lower temperatures in comparison to the south. The north has the least favorable vegetation growth conditions based on precipitation and temperature. Despite the above characteristics, it should be noted that concentrations of precipitation and favourable temperatures at opportune times of the year can also have a significant effect on growth characteristics similar to total rainfall or overall temperature differences. This effect is related to the vegetation species types and specific growth preferences.

Of arguably greater importance than growing conditions are the storm patterns that are common to Ontario. One of the most common weather events that adversely impact vegetation in close proximity to overhead conductors is wind. The area east of Georgian Bay and the entire central part of the Province is prone to significant damage from wind events. These events sweep weakened, diseased, decayed and overloaded branches into electrical facilities. They have resulted in heavy forest damage and widespread outages during all times of the year. Examples from recent years include the storms in the summer of 2006 and the winter storm that hit during the last days of 2008 as noted in Appendix C3.

In addition to wind storms, normal weather patterns for Ontario and the northeast place Hydro One in a region of high risk for ice storms. These events are particularly significant when planning UVM due to the fact that these storms place additional weight on vegetation and result in what are referred to as tree “grow-in” and “fall-in” power interruptions. They are especially common to northern climates with heavy snowfall and the propensity for ice accumulations.

3.1.3 UVM Program Attributes

In addition to identifying environmental and physical conditions of Hydro One’s service territory, CNUC set out to understand Hydro One’s UVM program. Much of the information that was identified by CNUC at the onset of the study is found subsequently in this report and in the charts of the Appendices. Some of the salient findings are listed below:

- Over the past three years, Hydro One has been increasing expenditures in UVM to reduce the average clearing cycle from historic highs of over 10 years.
- Approximately 90% of Hydro One’s system is considered to be rural or remote.
- Approximately 75% of lines are on-road allowance while the remaining lines are off-road.
- UVM staff is unionized and a hiring hall arrangement is in place to provide additional staff for peak periods.

- Hydro One's system reliability can be improved significantly if tree-caused interruptions are reduced.
- The lost time incident rate is 0.0 for the last 5.5 million worker hours (3 years).

3.2 Selecting & Engaging Peer Utilities

The background provided above about Hydro One's UVM setting served to guide the selection of peer utilities or what are also referred to as "comparable" utilities for the purposes of this study. Based on the background, the three families of criteria that CNUC selected to guide comparability are:

- Vegetation Cover & Density
- Weather Considerations (e.g. Vegetation Growth Considerations & Storm Paths)
- Customer Density (i.e. Rural Distribution System Characteristics)

A detailed discussion of all of the comparability criteria and the definitions used are contained in Appendix C. To meet the criteria, utilities should:

1) Be located in the following specific locations of North America that are comparable on the basis of vegetation and weather:

   a) Around Ontario or;

   b) Northeastern North America or;

   c) Western North America or;

   d) Southeastern North America

2) Have approximately 30 or fewer customers per circuit kilometre.

3.2.1 Utilities Selected

The comparability criteria outlined above were used as guidelines for selecting utilities. Based on the criteria, CNUC conducted a lengthy process to secure participation from utility companies. Approximately 60 utilities were initially contacted with some effort extended to solicit utilities that were outside the comparability guidelines. (CNUC's experience has been that subsequent analysis may show that particular companies are better comparators despite not fully conforming to the guidelines originally set.) 25 utilities including Hydro One responded to the request to participate. Hydro One provided four entries (i.e. Hydro One Total, Hydro One Northern Zone, Hydro One Eastern Zone, Hydro One Southern Zone), which brought the participation up to 28. Of the 24 utilities, excluding Hydro One, 10 did not meet the comparability criteria and were subsequently omitted from the study leaving a participation pool of 14 utilities (i.e. 18 including the 4 Hydro One entries).

The final group is not a homogenous group, but each one has qualities that make it a good comparator. It is the overall mix that provides a good sample. The utilities that participated and that were deemed to be "comparable" based on the above guidelines are:

Allegheny Power (West Virginia, Pennsylvania, Maryland, Virginia)

Appalachian Power (West Virginia, Virginia, Tennessee)

BC Hydro (British Columbia)

Central Maine Power Company (Maine)

Consumers Energy Company (Michigan)

Entergy (Louisiana, Mississippi, Arkansas, Texas)

Hydro One Networks # 12

Hydro One Networks Southern #72

Hydro One Networks Eastern #73

Hydro One Networks Northern #74

Indiana Michigan Power (Indiana, Michigan

Kentucky Power Company (Kentucky)

Northern States Power (Wisconsin, Michigan)

Ohio Power Company (Ohio)

Pacific Gas & Electric (California)

Pacific Power (Oregon, California, Washington, Idaho, Utah, Wyoming)

Public Service Company of Oklahoma (Oklahoma)

Southwestern Electric Power Company Arkansas

The companies that participated are all medium to large companies, having significant rural components and a high percent of forested land. The vegetation image below (R1), taken by NASA, is included in Appendix D to depict forest cover and density in North America. Using that image, polygons have been drawn to represent the service territories of participating utilities.

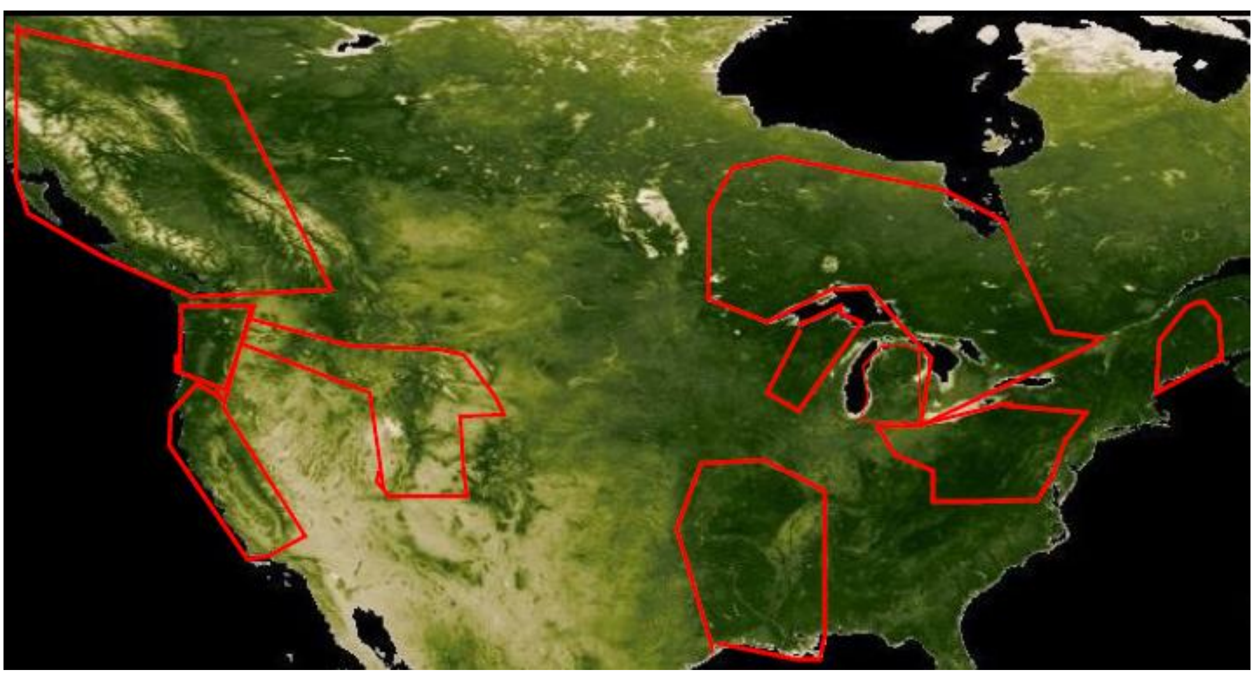


Fig. R1 NASA Vegetation Density and Cover

In terms of fullfilling the second set of comparability guidelines (i.e. weather and storm characteristics), the participating group of utilities are susceptable to significant storms and storm tracks as discussed in Appendix D. As previously discussed, storms impact storm restoration and system reliability and do influence UVM activities.

In terms of the final comparability criterion (i.e. high percentage of rural components), the two graphs below (R2 and R3) show that this set of utilities is a distinctly more rural subset than the full, industry wide set of utilities that have traditionally participated in CNUC's benchmarking studies. (R2 taken from 2005 CNUC study.)

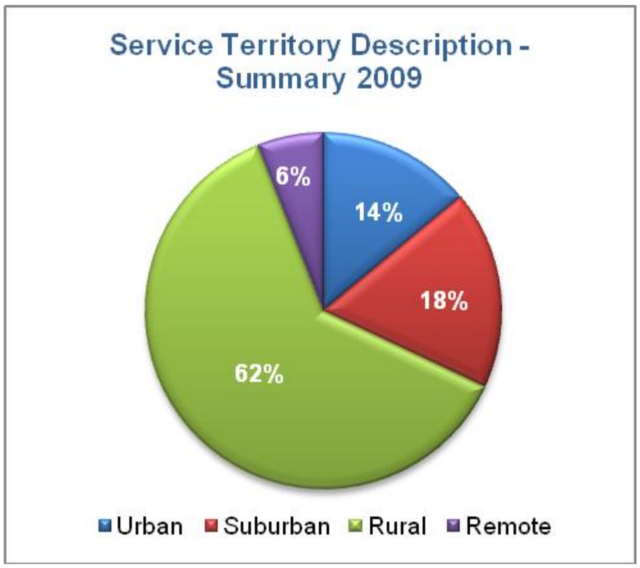


Fig. R2: Territory Description

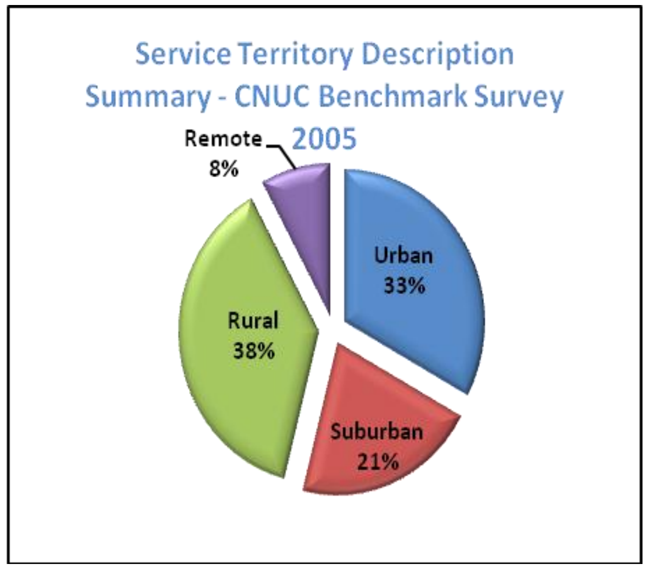


Fig. R3: Territory Description

The following chart (R4), illustrates how the group of companies compares in terms of customer density, which was one the criterion that was set above. The cross section of utilities range from approximately 10 customers per kilometre in the case of Hydro One to slightly greater than 30 customers per kilometre for utilities 41 and 3. It should be noted that Hydro One is the most rural of all participants in the study. Utilities 41 and 3 slightly exceed the 30 customers per kilometre threshold but remained in the study given that they substantially met the other comparability criteria.

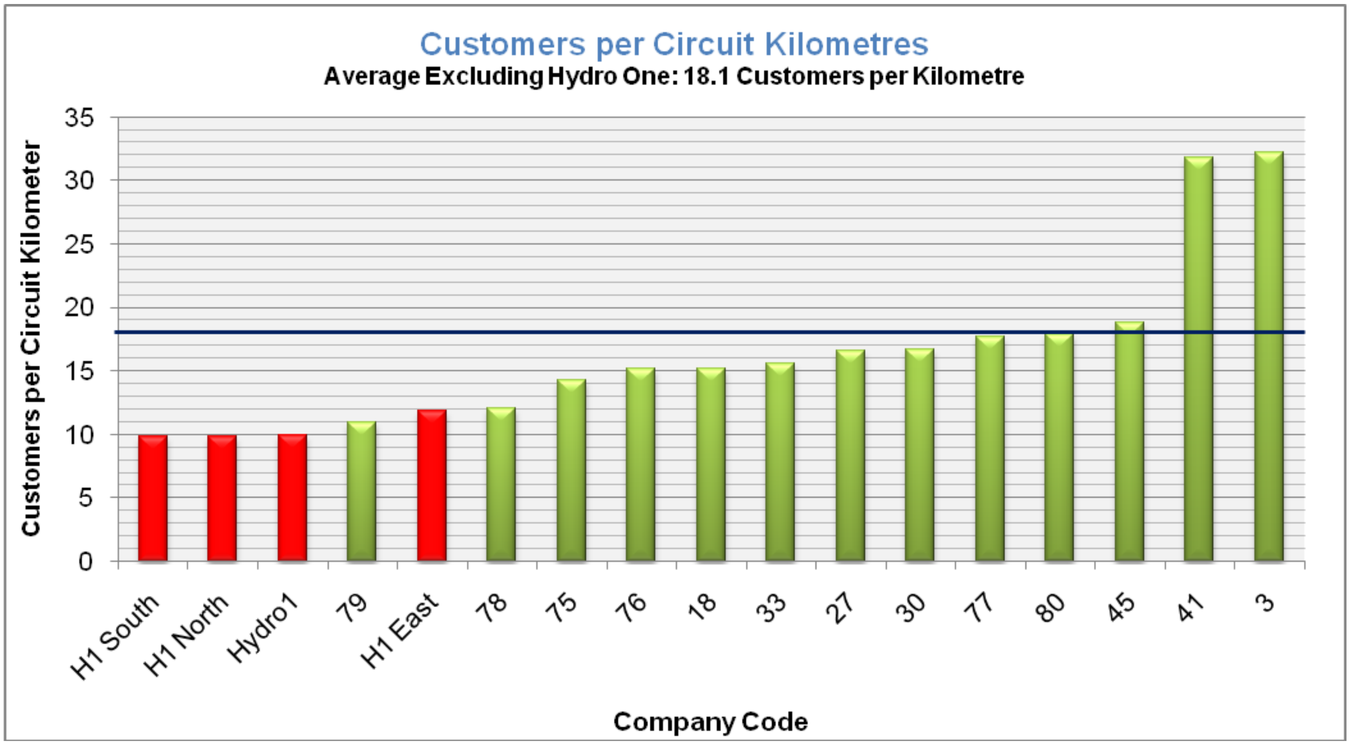


Fig. R4: Customer Density by Circuit Kilometre

3.3 Defining & Gathering Data

Based on the purpose and objectives of the study, CNUC decided to seek data in the following general areas:

- Utility Characteristics
- Labour Hours, Costs, Cost Drivers, and Operations
- Safety
- Reliability

These areas, fairly well cover the gamut of possibility for UVM measurements. To gather data, CNUC targeted both private and public sources. From a private perspective, CNUC used its extensive set of benchmarking information (i.e. data gathered in the 2002 and 2005 surveys) as a starting point. To obtain the latest information (i.e. 2006, 2007, and 2008), CNUC asked direct questions to participating utilities.

Public sources utilized in this study include OSHA, Canadian Health Statistics, Tree Care Industry Organization, Utility Company Web Sites, Forestry Sources for Canada and the US, previous CNUC Benchmark Studies and the U.S. Bureau of Labour Statistics. Another public resource that was highlighted as a potential source of data during the stakeholdering session to define the approach for this study was FERC. FERC Form 1 reports were examined and it was determined that no specific UVM measurements or expenditures are normally recorded. It was decided the value from FERC Form 1 reports was not sufficient to warrant including with this report.

3.4 Data Analysis

The data collected by CNUC was assembled and analyzed. The findings of the analysis along with the underlying data are contained in subsequent sections of this report and in Appendix E. This section focuses on the mechanics of the analysis and provides details related to the considerations made.

The data collected as part of the study was first condensed into information for further analysis and for finding anomalies and errors. All of the measurements were converted into metric units and Canadian currency (yearly average for each of the three sampled years). Measurements were validated and follow up questions were asked to qualify the comparison data.

It is important to recognize that currency conversions are done to facilitate fair comparisons between utilities operating in different countries but volatility and fluctuations in a currency's value over a short period of time may place utilities denominating costs in one currency or another at an advantage or disadvantage. In recent years, the Canadian dollar has appreciated significantly in relation to the US dollar. It reached a more than 50 year high on October 7, 2007 (i.e. $1 CAN = $1.10 US) and during the 3-year period that is the subject of this study (i.e. 2006 to 2008), the Canadian dollar averaged in excess of $0.9 US. The recent appreciation of the Canadian dollar over a short period of time places the Canadian participants in this study (i.e. BC Hydro and Hydro One) at a disadvantage, as the stronger dollar serves to increase their costs relative to US peers. This disadvantage, although existent, was not found to materially impact the study's findings.

Analyzing the data was complex process as individual utilities typically collected detailed data based on local and non-standardized definitions. Even standard industry measures related to reliability or safety had local subtleties that needed to be considered. As a result, all data and comparisons needed to be thoroughly analyzed and reconciled to ensure valid findings. The statement below underscores the challenges with capturing the most accurate and exhaustive information.

> *"Personal care of benchmarking participants is fundamental for data capturing. Cases of doubt and questions should be clarified by means of personal contact and via a hotline that answers questions with professional competence. Intensive care of benchmarking participants forms the framework for high quality data, enabling errors in data capture to be excluded."*[2]

Before moving on to the findings, it is important to provide two cautions in the benchmarking process.[3] First, the benchmark study performed on a single class of service such as Vegetation Management ignores the effects of interdependency between different classes of

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[2] *Benchmarking: a Fair Comparison,* by Dr. Bernhard Hartmann et al. PEI 7/26/09.

[3] *The Role of Performance Measurement in Rate Cases,* by John M. Shearman CEO & Chairman, UMS Group Inc.

service within a company. Second, the confidentiality of data collection that enables benchmarking to be performed, places a limitation on knowing all the facts for each participant.[4] If all participating companies were to agree to expose their information for all to scrutinize, like submissions to a juried competition, then a fully informed discovery process would ideally reveal best practices and efficiencies. However, such a full identity disclosure process could instead produce more leverage for some companies and diminish the value of others. With confidentiality secured, the best approach is to gather the data through a third party with recognized experience in the benchmark process and then present it in an organized manner. CNUC assumed the role of this third party and is committed to upholding the confidentiality of the participants.

4. Findings & Discussion

The following sections of the report detail the key findings based on data gathered. Findings are presented in two key sub-sections:

1) Efficiency & Productivity

2) Operational Attributes

The first sub-section provides comparisons that get to the heart of this study's purpose (i.e. how efficient is Hydro One). The second sub-section presents what are referred to as attributes that will impact or illuminate efficiency performance. This second section includes findings related to safety and reliability.

The findings contained below are what emerged during the data study and analysis phases as being noteworthy findings. CNUC also gathered data and conducted analysis in a wide variety of UVM related areas that extend beyond what is contained in the body of this report. That data and analysis is contained in Appendix E in the form of additional comparisons and data. It should be noted that the findings illustrated in the form of charts within the report body are illustrated in ascending order for a particular measure and contain only the utilities that provided responses. The charts in Appendix E contain all utilities in a consistent manner regardless of whether responses were provided or not.

4.1 Efficiency and Productivity

As noted earlier, the purpose of the benchmarking study is to obtain "definitive information respecting the Company's relative efficiency" in the area of UVM. Definitions of efficiency can be both qualitative and quantitative and typically relate to "doing things right" (e.g.

[4] *Ibid*.

best practices, safety) and to productivity. From a measurement perspective, efficiency can be defined as the ratio of input to output. In the UVM field, inputs are resources (e.g. labour hours, costs) and outputs are accomplishments (e.g. kilometres of line cleared, kilometres of line managed, number of trees treated). Asstated in the project objective, the findings reported are measurements of efficiency and factors affecting, qualifying, or validating efficiency.

4.1.1 Line Clearing & Brush Control Labour Hours

Line clearing and brush control activities form the core of the UVM program. These programs are characterized as labour intensive and CNUC sought information in these areas. CNUC found that many companies do not account for labour hours (and costs) separately in line clearing and brush control activities. For these companies, brush control is typically carried out by the same crew that carries out line clearing. As a result, measurements of unit quantities are not consistently recorded separately. Although Hydro One does separately account for line clearing and brush control programs, the state of the industry and the lack of standardized and consistent reporting necessitated an examination of these two activities in a combined fashion. The following chart (R5) depicts the labour hours per kilometer treated for the utilities in the study over a three year period.

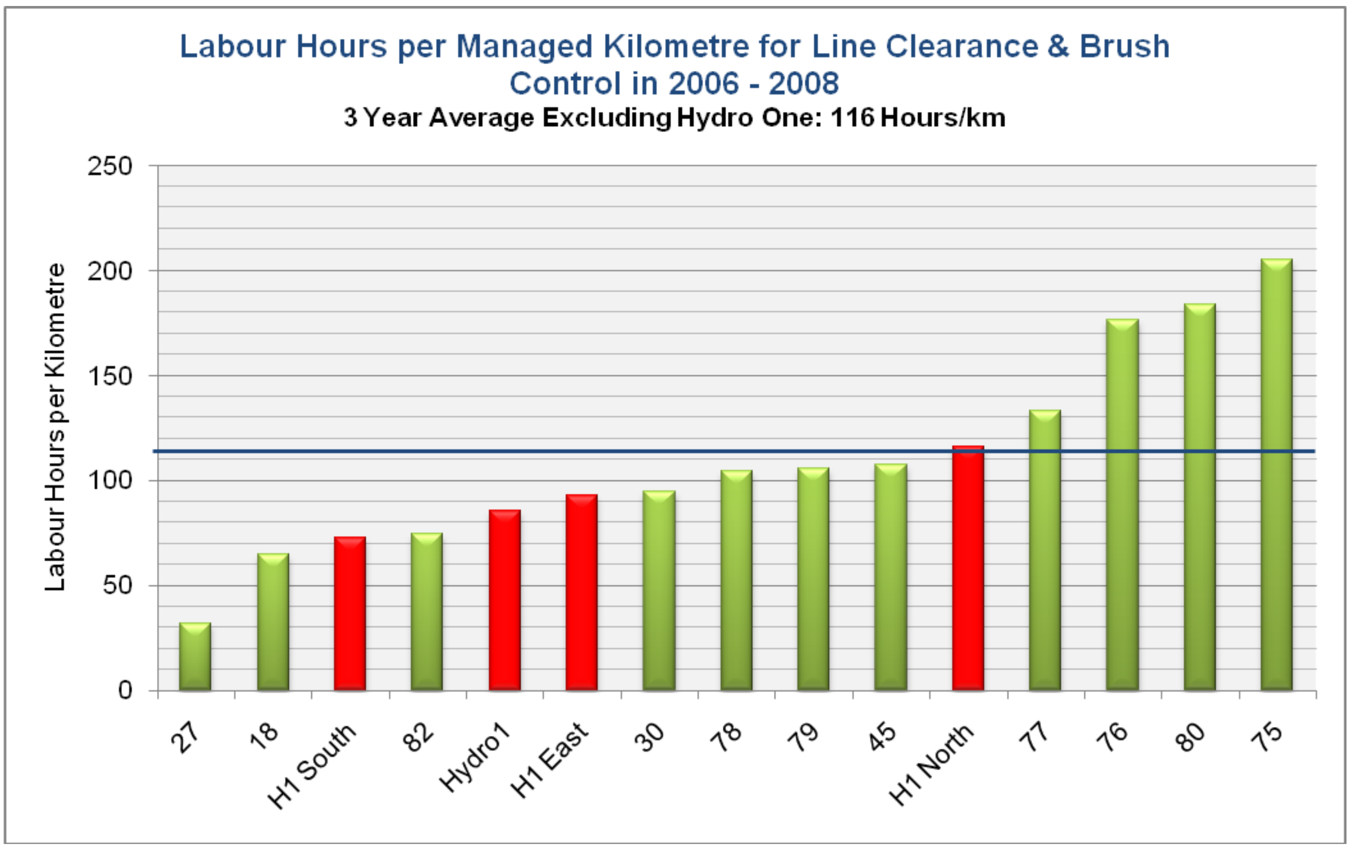

Fig. R5 Line Clearing & Brush Control Labour Hours per Kilometre for 2006-2008

The above chart (R5) illustrates that Hydro One and the Southern and Eastern Zones use less than the average labour hours per kilometre treated, while the Northern Zone is at the average but lags in comparison to the other Hydro One entries. When examining these results in light of comparability criteria and operational attributes (discussed in more detail in section 4.2 of this report), the reasons for these results become clear. The Southern Zone leads the other Hydro One zones as a result of its lower forest density, and fewer square kilometres of service territory, which reduce the need for long travel times. Furthermore, the Southern Zone treats 30% less trees per kilometre than the Eastern Zone and less than half the number of trees treated by the Northern Zone on a per kilometre basis.(See Figure R15)

In comparison to the peer group, Hydro One and its zones manage an above average number of trees per kilometre (See Figure R15 in section 4.2). Furthermore, this has been done on a cycle that is longer than the cycles of the peer utilities, which results in the need to address a significant amount of additional biomass. Simply put, Hydro One has a larger volume of UVM work per kilometre as discussed in greater detail in section 4.2 Operational Attributes of this report. Consequently, it is CNUC's position that Hydro One would be in the top quartile of performers for labour hours per kilometre if it was managing the average number of trees per kilometre and managing them on a shorter cycle.

Strong performance in the labour hours per kilometer measure is very telling as CNUC deems labour hour efficiency measures to be the best indicators of efficiency. The reason for this is that labour hours eliminate complications that are associated with cost measures such as currency exchange rates, or utility cost structure differences (e.g. contracting arrangements). Based on discussions with Hydro One, it is clear to CNUC that the company is focused on labor hours per kilometre as a measure of efficiency and is actively seeking to improve upon it. Evidence of this can be found in innovations that the company is pursuing. One specific innovation that Hydro One is currently piloting is the introduction of “mini-grinders”. These grinders are a type of mechanical equipment used to treat heavy and dense brush that would traditionally be addressed using time consuming manual labour. This innovation comes from Hydro One's experience managing Transmission right of ways and is expected to reduce the number of labour hours per kilometre.

4.1.2. Line Clearing & Brush Control Unit Costs

Efficiency for line clearing and brush control activities needs to also be examined from a cost perspective. Although these activities are labour intensive, they attract costs such as equipment (e.g. bucket trucks) and sundries (e.g. accommodations for remote jobs), As described above for labour hour comparisons, CNUC analyzed unit costs for line clearing and brush control in a combined fashion. The following chart (R6) illustrates the findings for cost per kilometre treated.

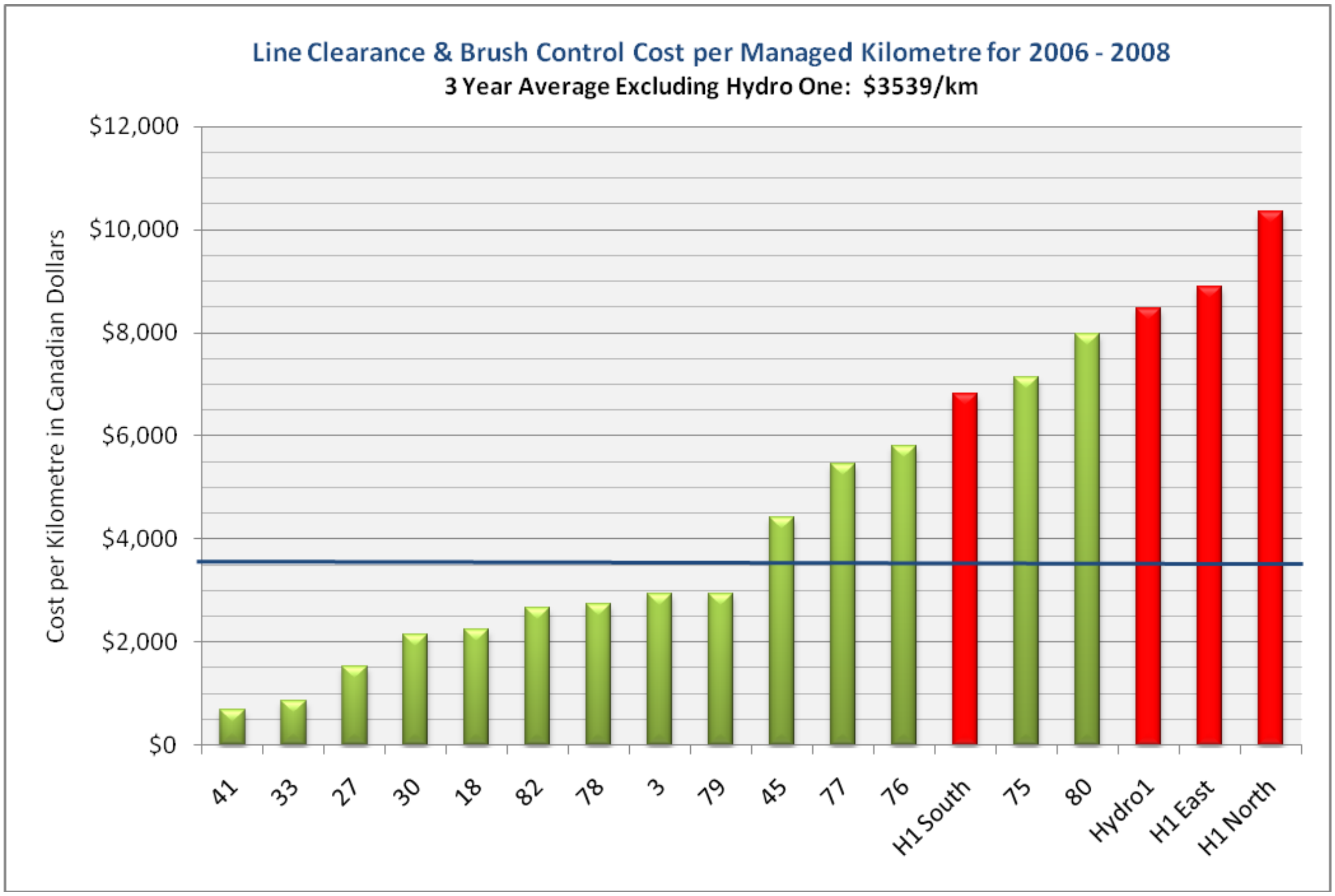

Fig. R6 Line Clearing & Brush Control Costs per Kilometre for 2006-2008

The chart above (R6) indicates that Hydro One and its regions are above the average. Of the Hydro One zones, the Southern Zone has the lowest unit cost and the Northern Zone has the greatest unit cost. The reasons for the relative performance differences between the zones themselves are the same as those explained above in the labour hour efficiency discussion and include differences in vegetation density and size of the service territory. The reasons for the performance differences between Hydro One and the peer utilities are a result of various factors that must be clearly understood in order to draw fair and accurate comparisons in terms of unit cost efficiency. The most influential of these factors are described in detail subsequently in this report but are summarized below for the purposes of a cost efficiency comparison:

1. Cycle Length – The longer the cycle length, the more vegetation mass will accumulate and will need to be cleared. This is arguably the greatest single factor that drives line clearing and brush control costs. This is illustrated by the fact that the leading utility in the above chart is number 41, which has the shortest reported cycle of all participants at one year. On the other extreme is Hydro One, which has the longest reported cycle length of all participants at 10 years. The other participants that reported a cycle operate on a 3 to 5 year average cycle length. The reduced growing time undeniably impacts

efficiency but a quantitative factor for normalizing performance based on cycle is not available.

2. Vegetation Density – Hydro One operates in a territory that has an above average density of vegetation. Hydro One treats approximately 56 trees per kilometre in comparison to the study average of approximately 33 trees per kilometre (See Fig. R15 in section 4.2). Naturally, the more trees that require treatment, the greater the cost to treat a kilometre. Hydro One's number of trees treated per kilometre, which is almost 70% greater than the average (i.e. 56 vs. 33), will undoubtedly impact its costs. While the impact of increased vegetation density can be assessed in qualitative terms, CNUC attempted to quantify the impact of this factor by adjusting cost per kilometre to reflect the differences in vegetation densities between the utilities. In making the adjustment, CNUC took a realistic approach and estimated that one third of a utility's costs are for fixed requirements such as mobilzing crews, dealing with logistical issues, and funding sundries. This proportion is not dependent on the number of trees treated per kilometre. To account for this CNUC separated out this portion for all utilities and then normalized the remainder on the basis of number of trees per kilometre. The results of the adjustment are illustrated in the chart below (Fig. R7).

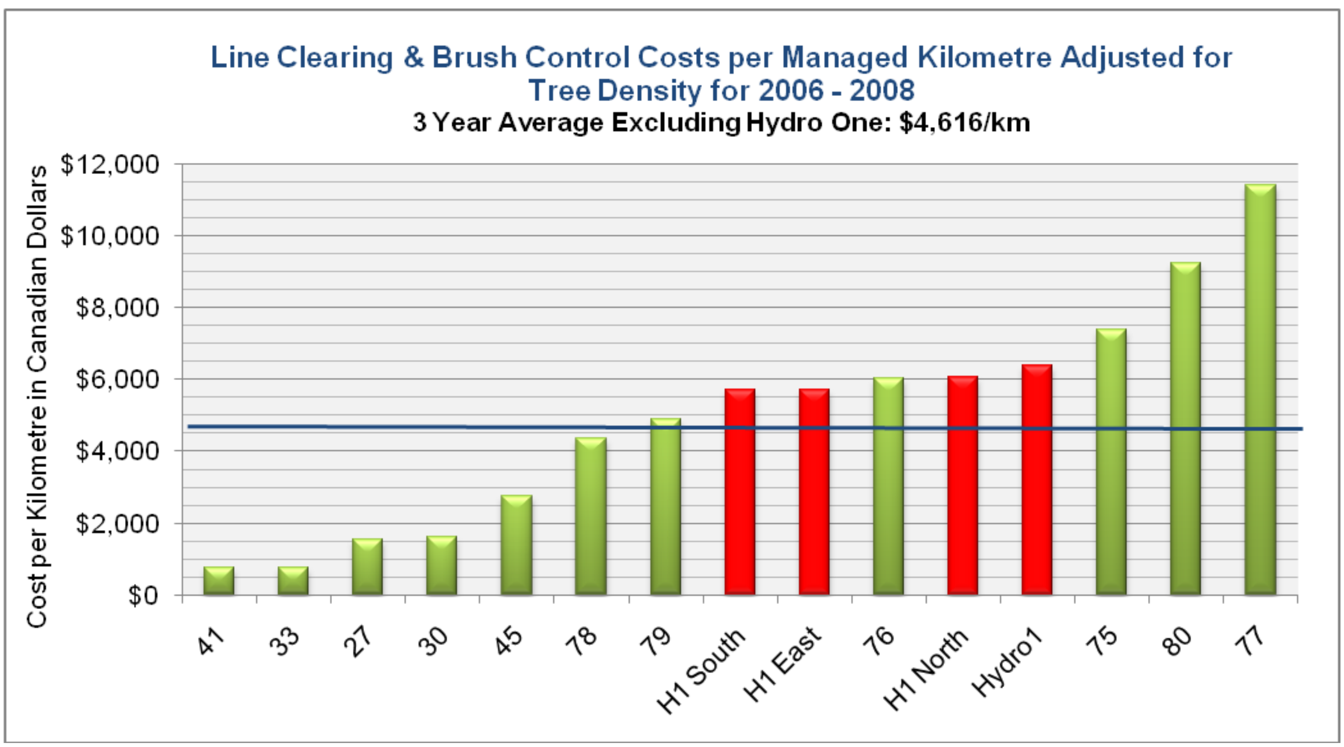

Fig. R7 Line Clearing & Brush Control Costs per Kilometre Adjusted for Tree Density for 2006-08

3. Other Factors -In CNUCs opinion, Hydro One's long cycle length and higher density vegetation service territory are the key factors impacting costs. However, other factors

that in CNUC's opinion also negatively impact Hydro One's unit cost efficiency in comparison to peer utilities include the following:

- Hydro One has the most rural system of all participants, which introduces challenges associated with greater travel times and accessibility.
- Hydro One is focused on safety, as discussed in section 4.2 Operational Attributes of this report, and must incur training and operational costs associated with safety priorities.

After considering the above factors, Hydro One's unit cost efficiency is closer to average. This is effectively illustrated in the chart above (R7), which is adjusted with consideration for vegetation density. Should adjustments also be made for the long cycle length and the other factors listed, then Hydro One's unit cost efficiency would be even better.

Despite being more efficient in labour usage than average and close to average in adjusted costs, CNUC has learned through discussions with Hydro One that the company is committed to continuously improving efficiency in the line clearing and brush control area. It is CNUC's understanding that Hydro One has increased and is planning to continue to increase its level of expenditure on line clearing and brush control activities (see Fig. 14 in Appendix E) in an effort to reduce the cycle and the volume of vegetation that is handled for each kilometre on the system. The utility has also introduced a series of innovations and improvements related to the usage of herbicides, which are also aimed at reducing the volume of vegetation. In the UVM industry, herbicides are considered a best practice because their application on standing vegetation leads to reductions in the volume of brush to be cut manually in the future. Unfortunately, there is much misinformation in the public domain about herbicides and their impact on the environment and this has made it challenging for many utilities to efficiently conduct UVM activities. Hydro One appears to have understood this and has undertaken the following initiatives and innovations:

- **Introduced a 1-800 Herbicide Phone Number** – The number is a dedicated hotline for customer and the public to call for herbicide inquiries. The line has given the public an outlet to obtain factual information about herbicides, thereby minimizing the amount of misinformation that travels in public circles and making easier for technicians to secure permission from property owners to use herbicides on rights of way.
- **Launched a study and pilot on the usage of herbicides -** This study consists of systematic plots that have been set up to test various herbicides, application techniques, and timing alternatives. The most effective techniques and applications will be utilized in the UVM program to improve cost efficiency.
- **Adopted a new and better nozzle for herbicide application -** This nozzle leads to improved herbicide application through more targeted and effective herbicide usage.

The above innovations, improvements, and initiatives are all aimed at improving efficiency through a focus on herbicide application that will reduce the volume of vegetation that needs to be addressed during future maintenance activities.

4.1.4. Labour Hours and Unit Costs Per Tree Treated (i.e. Pruned or Removed)

Another set of efficiency measures that can be examined are the unit cost and the labour hours required to treat a tree during line clearing activities. Utilities typically capture valuable statistics on the numbers of trees that are pruned or removed. Using these statistics, efficiency can be examined on a different basis than kilometres cleared. The following charts (Figs. R8 and R9), illustrate Hydro One's relative performance in terms of cost and labour hours per tree treated.

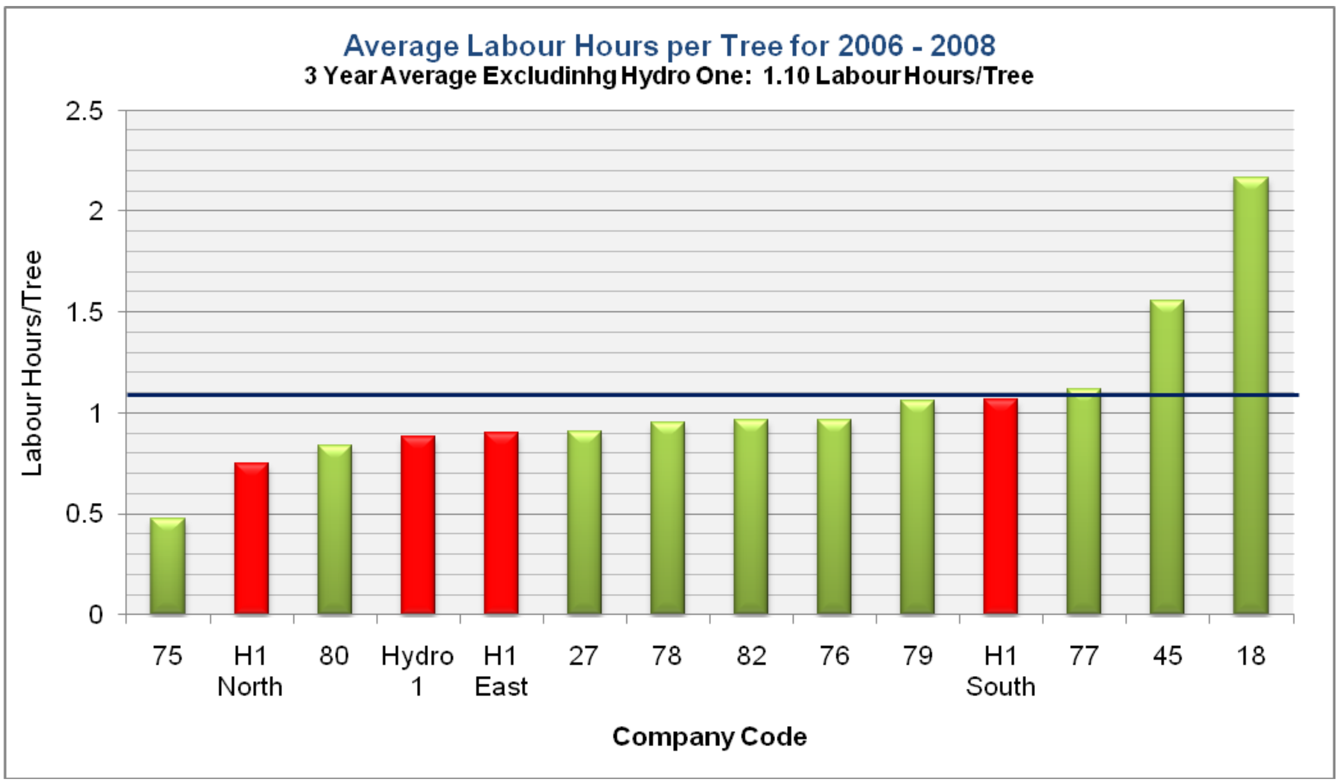

Fig. R8 Average Labour Hours per Tree in 2006-2008

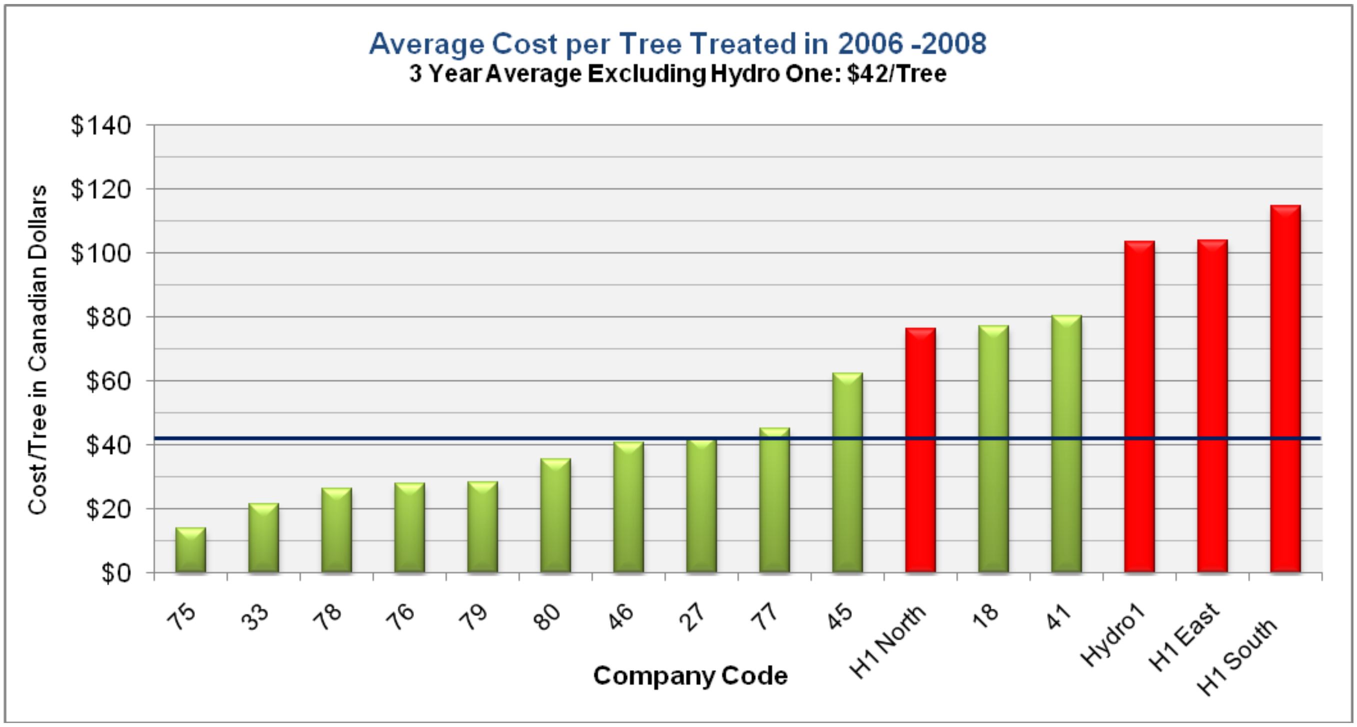

Fig. R9 Average Cost per Tree Treated in 2006-2008

The above two charts need to be examined in full context prior to ascertaining the relative efficiency of a utility. As with Line Clearing and Brush Control, the cycle once again plays a significant role as longer cycles will result in significant amounts of growth and the need for increased pruning efforts. This is considered to be one of the greatest drivers in both labour hours and cost and undoubtedly impacts Hydro One's relative positions in the above charts. As described previously, normalizing for this is challenging but in simplistic terms can be considered using the fact that some of Hydro One's peers in the study will be treating the same tree two or three times for every one time that Hydro One crews handle the tree. If the impacts of cycle length (e.g. additional growth and volume of vegetation) were to be factored in, CNUC expects Hydro One's relative efficiency to be average for costs per tree and to be significantly better than average for labour hours per tree. As noted above, CNUC has found resource allocation measurements to be more reliable when performance is measured in labour hours instead of dollars.

Beyond the cycle length, other factors that impact cost include the type of tree that is being treated, and the proportion of trees pruned to those removed (Appendix E, Fig. 33). The impact of these factors is evidenced in the performance of the Hydro One Northern and Southern Zones. The North has the greatest cost per kilometre in relation to the other Hydro One zones but has the lowest cost per tree treated. The performance of the Southern Zone is the opposite. This seemingly contradictory finding is attributed to the fact that the conifer trees that are predominant in the north are easier to remove (i.e. fell) and leave on the right of way given the remote nature of the service territory. The deciduous trees of the South on the other hand are more likely than in the North to require a significant amount of work from aerial devices or by climbing, are more time consuming to remove, and removed vegetation must be cleaned up and hauled away. These factors are illustrated more clearly later in this report when the percentage of removals is compared for the entire peer group.

In discussions with Hydro One, CNUC has learned that the utility is focused on improving efficiency in this area of UVM operations by proactively improving the tools available for its field crews. The best example of this is Hydro One's initiative with a tool supplier in California to develop a pruner that is a third lighter than traditional pruners. This pruner, which has been introduced on a trial basis, is easier to maneuver and will result in faster pruning and fewer injuries to staff given that it does not weigh as much as existing equipment. This tool is expected to improve efficiency as measured by cost per tree treated.

4.1.5 Customer Notification and Job Planning

After line clearing and brush control, utilities typically expend the greatest proportion of effort on customer notification and job planning. The following charts (R10 and R11) illustrate Hydro One's relative efficiency in terms of customer notification and job planning based on both labour hours and costs.

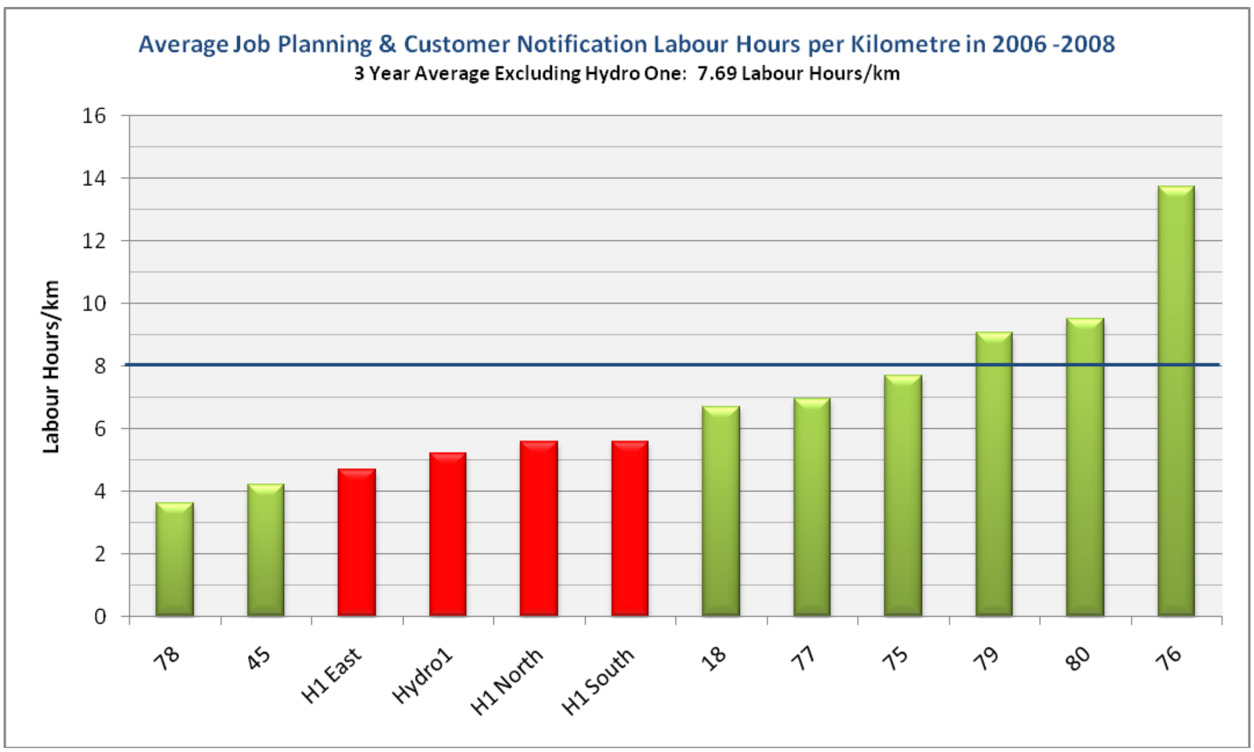

Figure R10 Average Job Planning & Customer Notification Labour Hours per Kilometre in 2006-2008

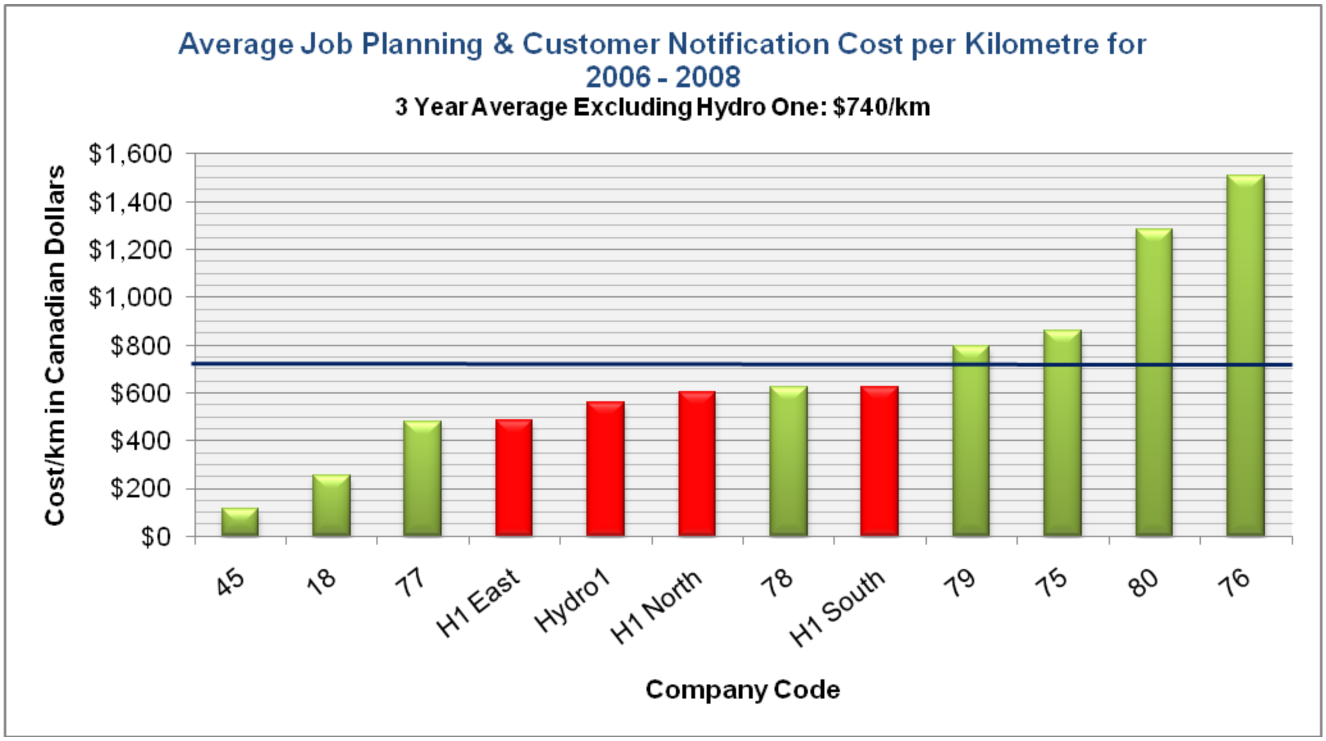

Figure R11 Average Job Planning and Customer Notification Cost per Kilometre for 2006-2008

The above charts illustrate that Hydro One and its zones are more efficient than the average in terms of both labour hours and costs. One factor influencing performance is the very rural nature of Hydro One's service territory and the fact that it will result in fewer customer notifications being required and a more streamlined effort. This factor does contribute to the performance but it is not significantly influential given that job planning also entails identifying trees for pruning and removal. In discussions with Hydro One, CNUC has learned that the utility's efficiency in this area is attributed to a number of innovations that have been adopted in recent years The most significant of these are:

1. **Introduction of Tablet Computers –** Starting in 2003 and 2004, technicians were equipped with tablet computers that are brought out in the field and used to document notifications and plans. The full integration of these units took a couple of years but benefits of their usage include streamlined data entry and documentation, field access to GPS and the Forestry Management System, and gathering of centrally and electronically available records related to notifications and plans that can be leverage during upcoming cycles.

2. **Linking the Forestry Management System (FMS) with Hydro One's Customer Service System (CSS)** – The investment to link the separate information systems has streamlined efforts by technicians to obtain customer specific information. CSS updates FMS on a weekly basis and this leads to better work tracking by customer, a greater understanding of customer request trends, and the need for less re-work and customer mailings.

4.1.6 Unplanned UVM Costs

UVM activities are typically planned with the exception of work that is done on a reactive basis as a result of unacceptable conditions (e.g. climbable trees near power lines; trees that are dead, diseased or leaning that threaten a power line) that cannot be allowed to persist until the next planned maintenance date. This unplanned work is the focus of this section. The chart below (R12) illustrates the relative efficiency of Hydro One's reactive UVM costs as captured by "Unplanned UVM" costs per system kilometre.

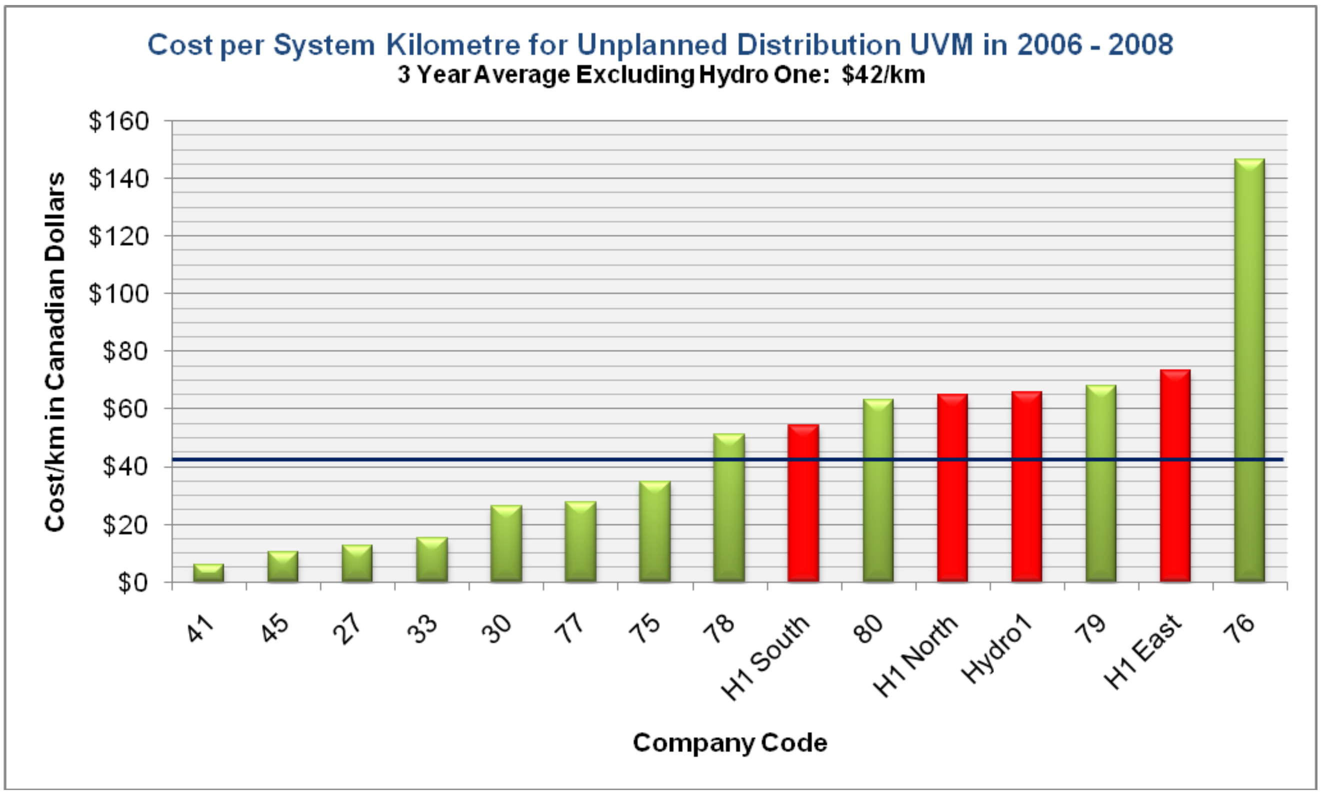

Fig. R12 Cost per System Kilometre for Unplanned Distribution UVM in 2006-2008

The above chart (R12) illustrates that Hydro One's unplanned costs on a system kilometre are higher than the average. This suggests that Hydro One is undertaking greater amounts of unplanned work than the peer utilities and indicates that Hydro One's system can be better controlled. Unplanned work is considered less efficient than planned work. The reasons for this is that unplanned work involves high priority locations, also refered to as "hot spots", that necessitate the mobilization of a crew to address an isolated and solitary issue on the system. This diverts crews from planned work, which entails the mobilization of a crew to treat vegetation in a systematic and economically efficient manner. As efforts expended on unplanned UVM increases, the deeper a program is sliding into a spiral of an exponentially increasing workload due to the reactive and non-systematic manner of treating vegetation.

The level of unplanned work is also related to the reliability performance of a system and to storm restoration expenditures. Reliability is examined subsequently in this report and findings in that area will confirm that Hydro One's system can improve control over the vegetation in its service territory. In the case of storm restoration activity, CNUC did gather costs from utilities for the 2006 to 2008 period as is illustrated in Appendix E. As these costs are dependent on highly variable storm events, it is not surprising that the restoration costs associated with UVM do vary significantly from one year to the next. The greatest variation is for Utility 3, for which costs were almost $70 million in 2006 and below $10 million in 2008. Other utilities, (e.g. 75, 77, 80) including Hydro One, experienced variations in costs year to year, although not to the same extent as Utility 3. Some utilities did however remain consistent during the three year period. Given the highly variable nature of storms and the associated restoration costs, CNUC concluded that a three year period did not provide enough data for the purposes of drawing efficiency conclusions. As such, storm data collected was included in Appendix E for illustration purposes.

4.1.7. Overall UVM Costs

The final efficiency measure that is examined is the ratio of total UVM costs to total system kilometers. This comparison is included for completeness but is not considered as precise as the comparisons that were conducted in the above subsections. Total UVM costs include those discussed in the previous sections of this report (i.e. costs for line clearing and brush control, customer notification and job planning, and unplanned activities) along with other costs that utilities deemed to be a part of their UVM programs but that were not directly comparable on an individual basis between the peer utilities. These include overheads (e.g. program management), storm restoration activities, and other costs (e.g. targeted danger tree removal programs). The following chart (R13) compares Hydro One's total UVM annual costs on a per system kilometre basis to peer utilities.

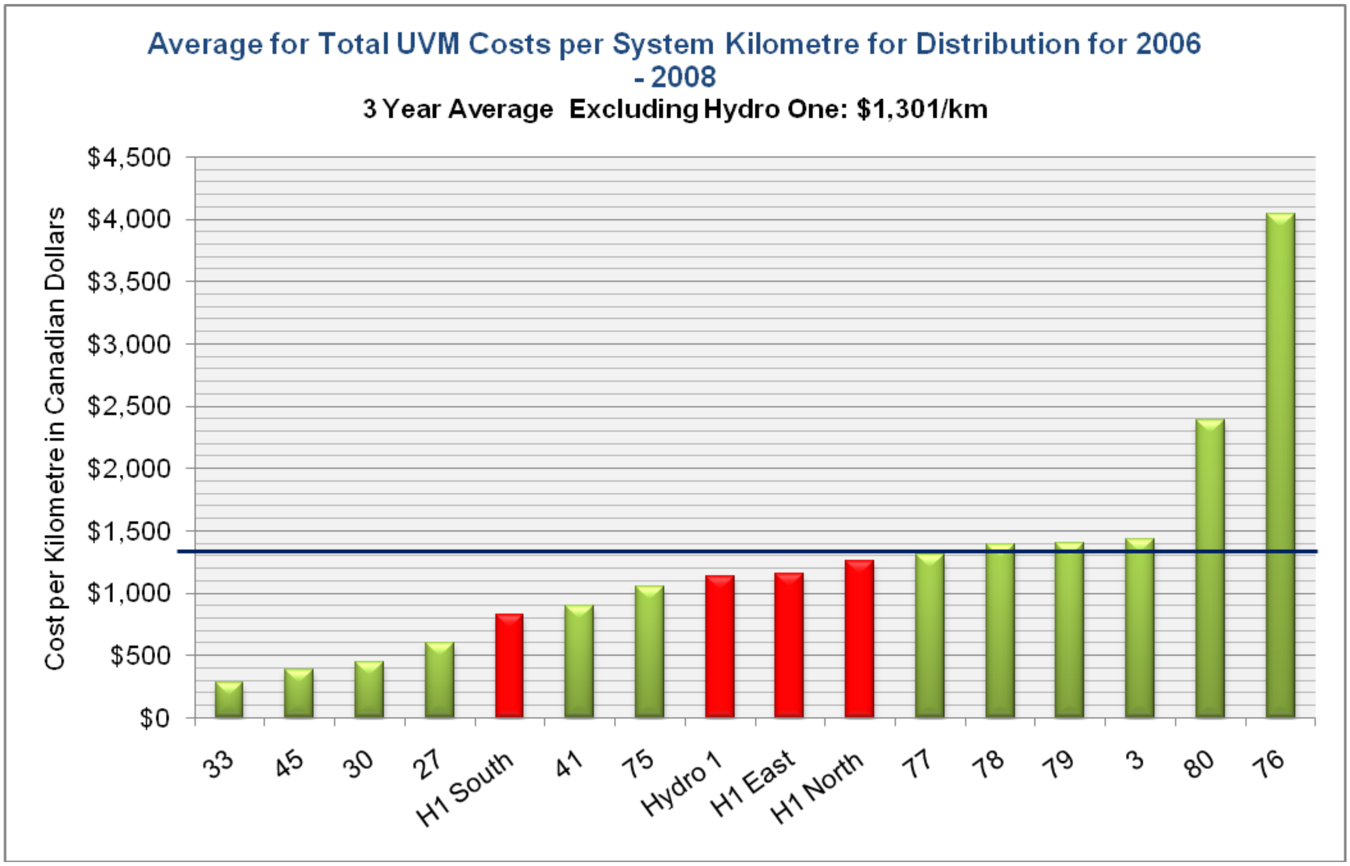

Fig. R13 Average for Total Costs per System Kilometre for Distribution 2006-2008

In the above chart (R13), Hydro One's performance is below average cost. Looking at total UVM costs, peer utility costs range from a low of approximately $300 per kilometre to a high of almost $4000. The average is approximately $1300 and Hydro One's average is approximately $1100. Of the Hydro One zones, the performance of the Northern Zone is the worst and the performance of the Southern Zone is the best.

Hydro One's performance in the above measure is influenced by the factors that have been discussed in previous sub-sections of this report. Although the impact of the cycle length factor that was previously discussed is minimized when using a per system kilometre measure, the impacts of vegetation density and rural service territory continue to exist. In addition, Hydro One has over the past three years, made a concerted effort to reduce its cycle time. Cycle transition periods are typically less efficient periods of operation for any utility as additional funds need be spent to increase accomplishments. For example, a reduction in cycle from 10 years to 8 years will involve a period of time where the number of kilometers maintained is in line with an 8-year cycle but the vegetation being treated has been growing for about 10 years on average and therefore presents added work load when compared to a steady state of 8 years. Hydro One currently finds itself in this period where the workload has increased and estimates are that if the company was not in a transition phase, then efficiency based on the above illustrated measures would be approximately 10% better.

Given the performance in the chart above and the factors identified above, CNUC assesses Hydro One's efficiency on the basis of Total UVM Costs per System Kilometre to be better than average.

4.2 OPERATIONAL ATTRIBUTES

The previous section focused on efficiency measures and contained discussion about the factors and operational attributes that can and do impact efficiency performance. This section elaborates on the operational attributes and provides additional discussion that places the efficiency comparisons made in the previous sub-section into context. .

4.2.1. Cycle Length

This section elaborates on the significance of cycle length in relation to efficiency measures such as cost and labour hours per kilometre, and cost and labour hours per tree. The definition of an average cycle and the exact execution of maintenance on that cycle vary throughout the industry. The traditional definition of cycle is the time that it takes for the entire system to be maintained once for vegetation. How a utility executes this varies and is illustrated by the utilities contained in this study. For example, company 41 in the study, reports managing on a one year cycle and patrolling the entire system once a year, treating only those trees that will potentially grow into the lines before the next patrol. This yearly project is performed on the entire system. Company 3, on the other hand averages a 4 year cycle but does vary maintenance in particular locations. In Hydro One's case, the historic average cycle has been 10 years. The following chart (R14) illustrates the average cycles reported in the study.

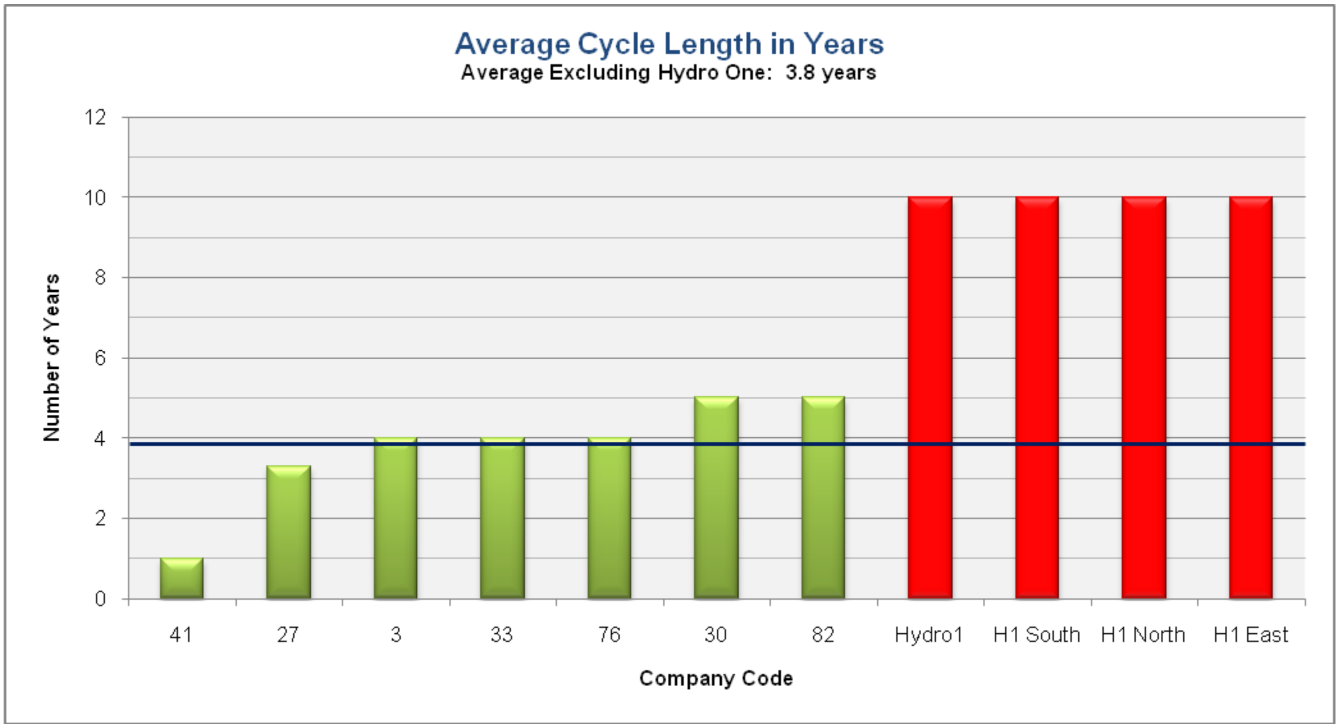

Fig. R14: Average Cycle Length in Years

As illustrated in the chart (R14) above, Hydro One and its zones have the longest cycle of any utility in the peer group. This long cycle is undeniably contributing to higher per unit costs depicted in the charts provided in this report. In relation to the other utilities, it is CNUC's opinion that Hydro One is working a remediation program. Re-growth and new starts are abundant over the course of a decade. Long cycles between treatments push the workload on an upwardly exponential curve each time it is managed. When stump re-sprouts and new trees are allowed to grow higher than the shrubs, herbs, and grasses, the trees will extend their height rapidly to the height of the wire causing a need for remediation and unplanned maintenance.

UVM arboricultural experience tells us the work is the lightest and moves the quickest when it is performed before new vegetation begins the juvenile phase of growth, exponentially accumulating biomass. Experience also tells us that a least disturbed ecosystem (i.e. less biomass removed results in less vegetation and soil disturbance) results in the least introduced invasive vegetation that is not compatible with rights of way. Finally, and perhaps most importantly, vegetation that has not yet made contact with the conductor nor is overhanging the conductor is far easier, safer and quicker to manage. These conditions are not normally possible when vegetation systems have been developing for a decade.

Based on reported average cycle lengths, Hydro One is operating on a cycle that is at least twice as long as the peer utilities. The conclusion drawn from this key finding is that Hydro One's long cycle has resulted in excessive growth that naturally drives unit costs higher than those at utilities employing a shorter cycle. Based on this finding, Hydro One is making the prudent choice to reduce its cycle length.

4.2.2 Vegetation Density & Tree Removals

The following chart (R15) depicts the number of trees that Hydro One is treating relative to the peer utilities.

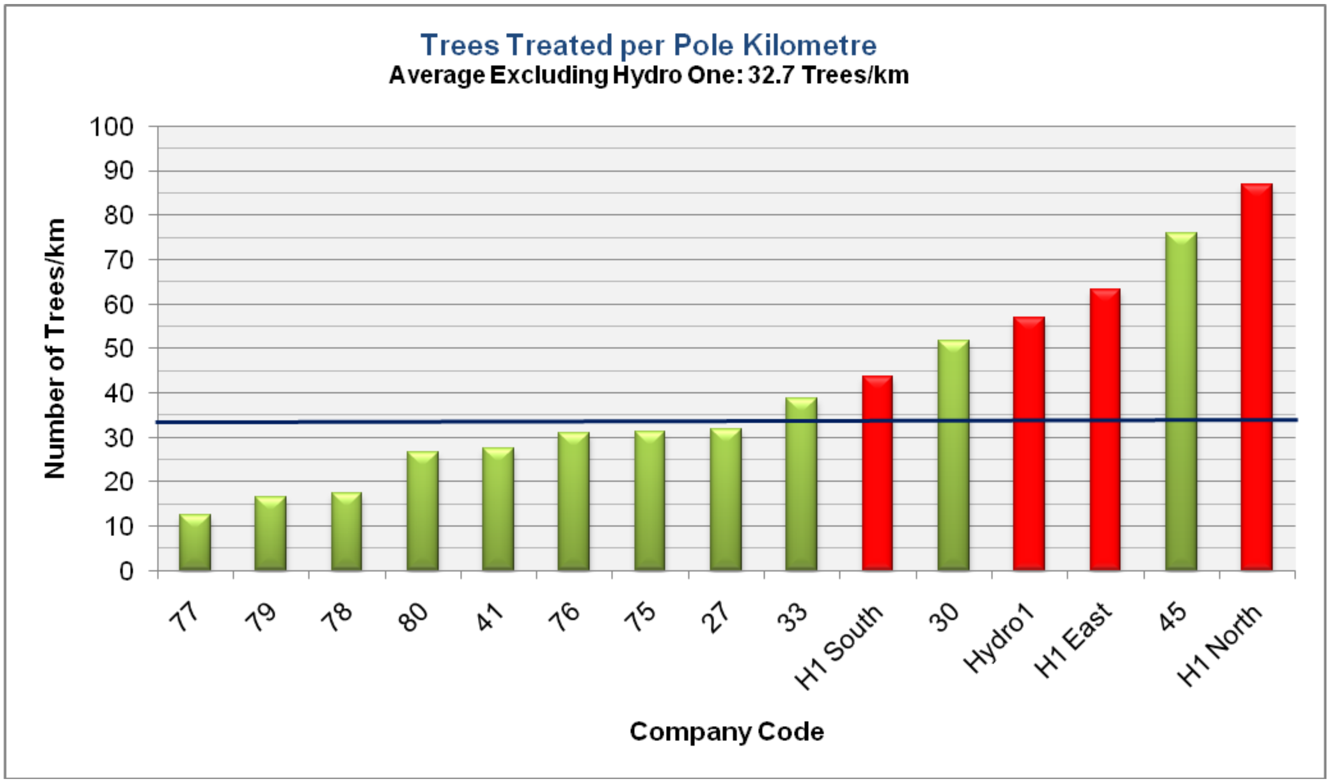

Fig.R15 Trees treated per Pole Kilometre

The chart (R15) illustrates that Hydro One is treating among the highest number of trees on a per kilometre basis and indicates that Hydro One's service territory is among the densest in terms of vegetation. The range of tree densities is between a low of approximately 10 trees per kilometre to a high of almost 90. The average is approximately 33 trees per kilometre and Hydro One's average is almost 70% greater than this figure. This statistic is telling in that it is evidence that Hydro One's workload is naturally greater than the average experienced by the group.

Vegetation density as measured by the number of trees treated per kilometre is not an absolute figure as it is also influenced by the cycle length to some extent. Long cycle lengths tend to increase the number of hazard trees (i.e. dead, dying, or diseased) that pose safety or reliability threats and must be removed. If these trees were not deemed to be hazards, they would likely be pruned or in a best case scenario, not touched at all, thereby resulting in a minor reduction in the vegetation density statistics presented above. Further information on the percentages of removed and pruned trees is illustrated in the chart (R16) below.

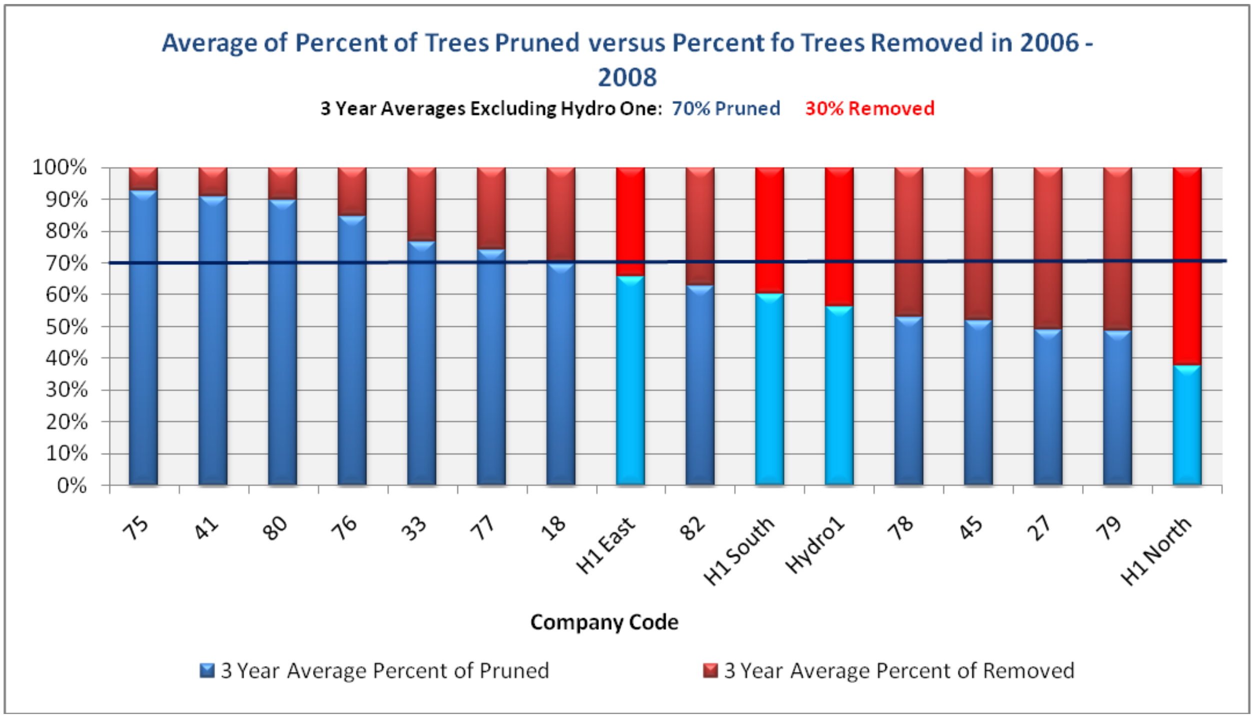

Fig. R16 Average percent of trees Pruned versus Percent Trees Removed in 2006-2008

The average removal percentage is approximately 30% and Hydro One is removing approximately 40% of the trees treated, with the exception of the Northern Zone where the percentage is almost 60%. With the long cycle, the high percentage of removals in the North is an appropriate practice in that it is the most cost effective method of managing tall growing coniferous trees that prevail in areas where mid-cycle remediation efforts are very expensive and there are fewer customer concerns limiting removal efforts. In the mixed and deciduous environments of the Eastern and Southern Hydro One Zones, the high number of removals is associated with prodigious new growth during the long cycle as described above.

In the Eastern and Southern zones, removals are typically more expensive than pruning. This increases the cost per tree and is a large driving force behind Hydro One's high cost per tree results illustrated above in this report. Costs to prune a tree are typically two thirds to half the costs to remove a tree. A long cycle length increases the proportion of trees removed, as seen in Hydro One's program. These trees would have been treated using alternative methods (i.e. pruning, cut as brush, or spray with herbicide) under a program with a shorter cycle.

4.2.3 Safety

Some measurements stand alone and comparisons do not carry as much weight as the data itself. One example is the fact that Hydro One has worked 5.5 million hours (i.e. 3 years) without a lost time accident in the line clearance industry.

CNUC sought to compare Hydro One's safety performance to the industry using publicly available statistics. What it found was that there is some variation and discretion in these measurements that differ between Canada and United States, but in general CNUC was successful in comparing performance. An example of this is a US Department of Labour survey of the seven largest Utility Line Clearance Coalition (ULCC) members, who collectively employ 33,000 line clearance arborists. For 2007, the group's average lost time incident rate was 3.1. This rate is lower than the rate for Logging (i.e. 5.3) and the rate for the general category that line clearance is listed in by the Bureau of Labour Statistics (i.e. Landscaping Services - 5.9). [5] In comparison, Hydro One's rate of zero (0) lost time injuries for 2007 and 2008 is impressive.

To put Hydro One's performance into context, 2750 workers working one year is equal to 5.5 million worked hours. The average rate for Arborists, which is over 5.0, would mean that over 137 injured employees out of 2750 were significantly restricted from performing their job in the course of one year. Hydro One had zero. The impact of that on efficiency is noteworthy but unfortunately difficult to measure. The impact is positive for worker moral, leads to employee longevity and retention of skilled staff, and ends with more days on the "tools".

Given Hydro One's safety record and the relationship that it has to efficiency, CNUC sought information from peer utilities to compliment the information obtained from public sources. Requests for safety performance information yielded mixed results. Many utilities provided work to multiple contractors and as a result, safety statistics were of questionable reliability if available at all. To complicate matters, different utilities preferred different measures and reported based on their preferences. Appendix E contains illustrations of the information that was collected privately from the utilities. This information also confirms that Hydro One's performance of zero lost time incidents is best in class.

In discussions with Hydro One, CNUC identified a number of initiatives that have helped the company achieve a best in class safety record. Among them are focused training for staff and an integrated Health Safety and Environment System that is based on ISO 14001 and OHSA 18001 standards.

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[5] Department of Labour Proposed Rule Making—Tree Care Operations Standard, Docket No. OSHA-2008-0012: "Comments of The Utility Line Clearance Coalition", (ULCC): Asplundh Tree Expert Co., Davey Tree Expert Co, Lewis Tree Service, Inc., Lucas Tree Experts, Inc., McCoy Tree Surgery, Inc., Nelson Tree Service, Inc., Tamarack Tree Service, Inc., Townsend Tree Service., Trees Inc., Wright Tree Service." (2009) By Melissa Bailey, Counsel to ULCC.

4.2.4 Reliability

Earlier efficiency comparisons examined the costs of unplanned and storm restoration work. This work is closely related to system reliability and is a strong indication of how well controlled the vegetation in a service territory is. Furthermore, most utilities, as illustrated in the chart below (R17), report that after safety, the number one reason for operating a UVM program is to ensure reliable electric service to customers. As a result, CNUC sought reliability information to validate earlier observations made with respect to the need for reactive UVM activities and to assess how successful UVM programs are at meeting reliability objectives.

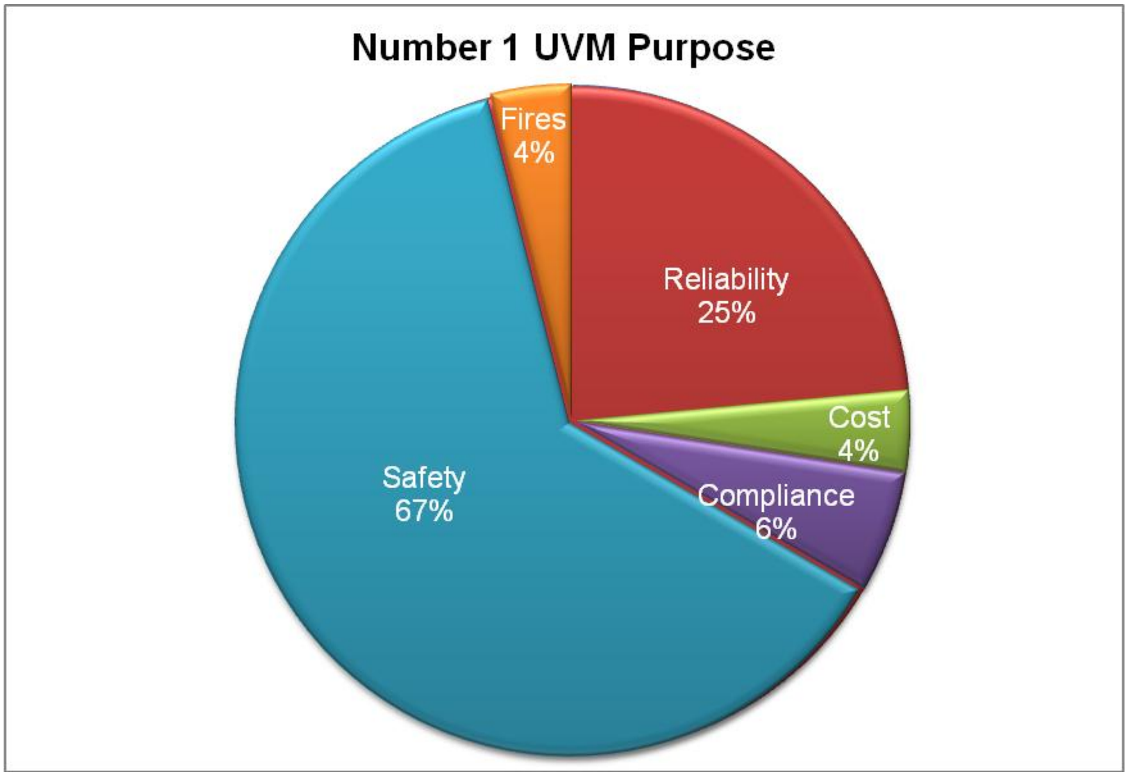


Fig. R17: Number One Purpose for UVM (2005 CNUC Benchmark)

The first chart below (R18) illustrates the tree caused SAIDI for the utilities that participated in this study. The second chart (R19) illustrates the contribution to total SAIDI that tree caused interruptions make. Similar charts for SAIFI along with additional reliability comparisons can be found in Figs. 40-48 in Appendix E.

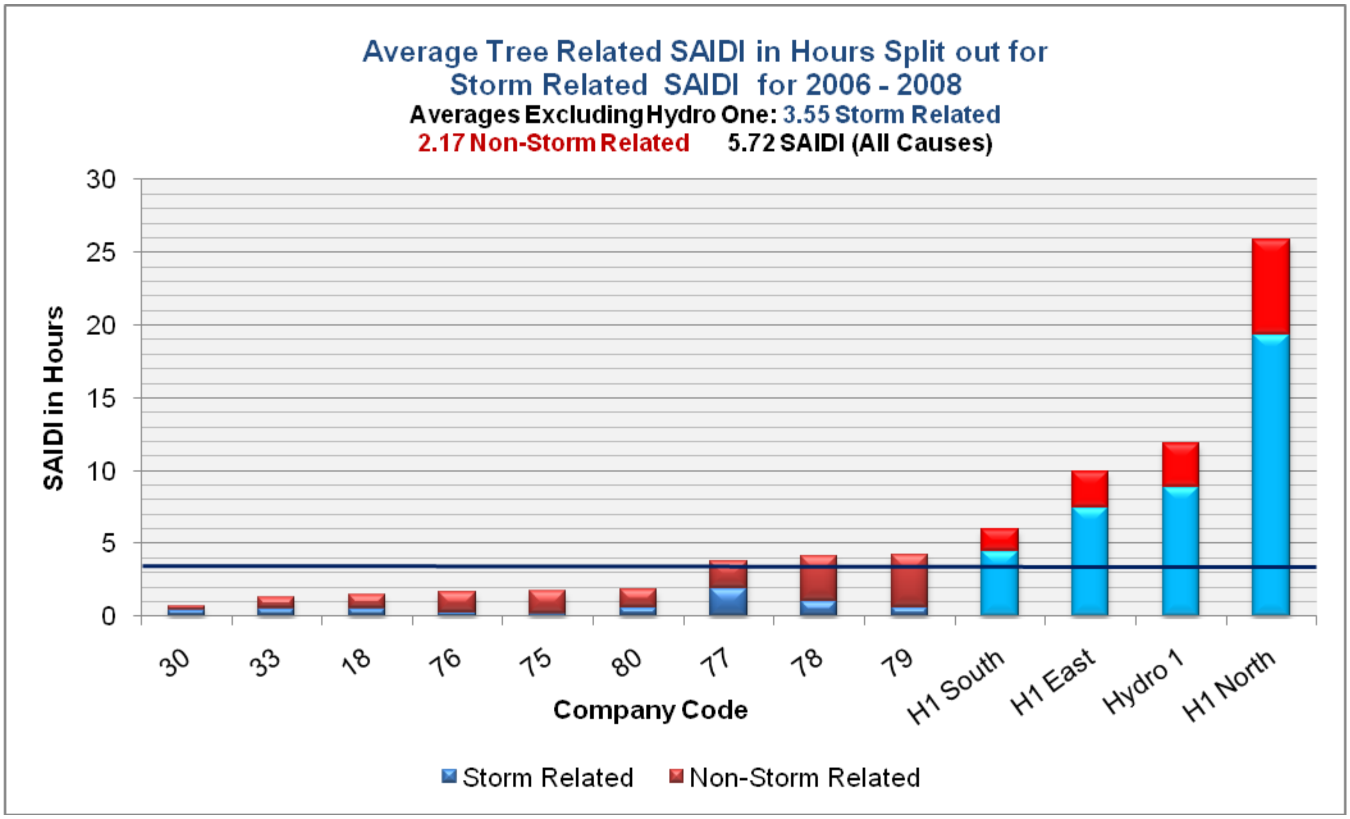


Fig. R18 Three Year Average of Tree Related SAIDI for 2006-2008

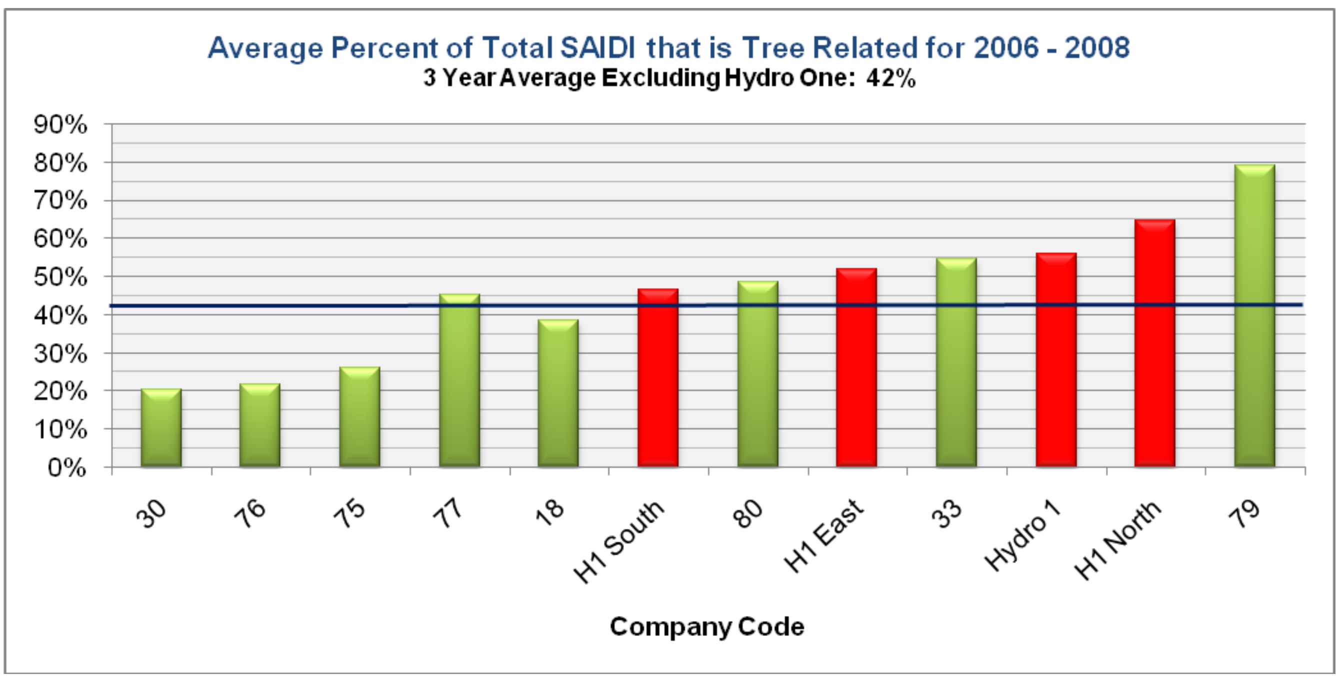


Fig. R19 Average Percent of Total SAIDI that is Tree Related for 2006-2008

The above charts (R18 and R19) illustrate that Hydro One's tree caused SAIDI is the highest in the peer group. In particular, Hydro One's system is very vulnerable to storm activity as is evidenced by the high storm impact on reliability. The single year averages found in Fig. 43 in Appendix E illustrates how Hydro One's system is particularly vulnerable to storms. In terms of contribution to overall SAIDI, Hydro One performs better on this measure but remains worse than average. These findings, like the efficiency measurements made previously in regards to unplanned costs indicate a system where vegetation is not well controlled. Given Hydro One's lengthy cycle in comparison to the peer group, these findings are not unexpected and utilities with shorter cycles will naturally perform better. An additional input is the vegetation density associated with Hydro One's service territory. As previously discussed, Hydro One's service territory is more densely vegetated than the average for the study group. This will also impact reliability performance.

CONCLUSIONS

Efficiency & Productivity Summary

1. Hydro One and its zones have better than average efficiency in labour hours for line clearing and brush control activities. While the results compare favourably to peer utilities, the factors discussed under bullet (2) below are also applicable and when considered suggest Hydro One's efficiency is excellent on the basis of labour hours.

2. Hydro One and its zones have greater than average costs per kilometre and per tree; however the performance is negatively influenced by a number of factors as listed below. When adjusted for the factors, Hydro One's performance is better than average. The factors include:

    i) Hydro One has a more densely vegetated service territory and is managing almost 70% more trees than the peer utilities.

    ii) Hydro One is performing work based on a ten year cycle, which is longer than all of the cycles reported in this study. A long cycle results in significant growth and the need to remove great volumes of biomass during line clearing and brush control.

    iii) Hydro One has the most rural and remote service territory of any utility in the study as measured by customer density. This results in the need to travel long distances to access work sites and overcome barriers that increase costs.

    iv) Hydro One is working in a harsh weather climate based on significant storm activity throughout the course of a year along with relatively low temperatures in the winter. This challenges UVM operations and places upward pressure on costs.

3. Hydro One and its zones have better than average efficiency in terms of both labour hours and costs associated with customer notification and job planning.

4. Hydro One and its zones have worse than average efficiency in the area of unplanned costs. This is expected given the long maintenance cycle length.

5. Hydro One's overall UVM costs per system kilometre are lower than the average.

Operational Attributes Summary

1) Hydro One has the longest reported average cycle length in the study at 10 years, which is twice as long as the next closest participant. This places Hydro One's cycle length on the fringe of acceptable UVM practice and leads to inefficiencies as a result of excessive vegetation growth between successive maintenance.

2) Hydro One has one of the highest vegetation density service territories and naturally has a greater workload than the average peer utility.

3) Hydro One has a best in class safety record that is evidence of a well managed UVM program. The achievement of such a safety record is the goal of every company and worker, but it necessitates significant training costs and requires the adoption of safe work practices that at times can negatively impact efficiency when it is measured on a labour hour or cost basis.

4) Hydro One is plagued by a high degree of tree caused unreliability. This is a sign of system that can significantly improve the control of its vegetation and one that is expected when maintenance cycles are in the range of 10 years.

Concluding Remarks

Despite having a naturally challenging (e.g. high vegetation density, extreme weather) service territory, Hydro One has proven to be efficient. In particular, normalized measures on the basis of vegetation density indicate that efficiency performance is generally very strong with reference to labour hours and close to average on the basis of costs. To further improve efficiency, CNUC is of the opinion that Hydro One needs to reduce its UVM cycle. It is apparent, through comparisons with peer companies, that Hydro One’s cycle is significantly longer than peer utilities and that more frequent treatments will allow Hydro One to get closer to the mainstream of good utility practice. Shorter cycles will reduce costs on a per kilometre basis as less biomass will need to be removed, will improve the control of vegetation and thereby reduce the need for unplanned UVM activity, and will improve the reliability of Hydro One’s distribution system.

APPENDIX A – CNUC EXPERIENCES AND ACHIEVEMENTS

As a third party Consulting Team, CNUC brings the following areas of expertise into this project:

- General consulting experience in areas such as UVM program reviews, audits, and projects.
- CNUC owns and operate the UVM industry's dominant web site, Tree Line Connection at www.utilityarborist.com.
- Expert witness experience for utilities across North America in both legal and regulatory proceedings related to trees and power lines. (E.g. Indiana Electric Utility Association to testify at a joint state legislative hearing about why utilities have to do UVM work.)
- CNUC's President was one of the 2 principal UVM investigators for the Joint US/Canada Task Force investigating the August 14th 2003 northeast Blackout and was commissioned to do this work by the Federal Energy Regulatory Commission (FERC). He was the principal author of the preliminary and final UVM reports related to the Northeast Blackout.
- CNUC's President is currently a member of the NERC UVM FAC-003 Standards Drafting Committee. This committee has developed and is continuing to refine national standards for required clearances between vegetation and subject transmission lines across North America. He also served on the first FAC-003 Drafting Committee.
- In August 2003, CNUC's President received the 2003 Utility Arborist Award in Montreal Canada during the International Society of Arboriculture annual conference. He received this award in recognition of his work in support of this industry.
- CNUC's President is Past President of the Utility Arborist Association, which is the industry dominant non-profit organization devoted to Utility Arboriculture.
- CNUC continues to work very closely with the UAA and the Edison Electric Institute's Vegetation Management Task Force in furthering the UVM industry. Most recently, CNUC's President was directly involved with setting up and attending meetings in Washington DC with the UAA and EEI Vegetation Management Task Force leadership.
- CNUC's President was one of the few industry experts chosen to develop the ISA advanced certification exam for Utility Specialists.
- CNUC has participated in the development and review of numerous industry publications which are considered standards in the industry. For example, CNUC's President was a review committee member for the current ISA Best Management Practices for both Utility Pruning of Trees, and Utility IVM.
- CNUC has completed various utility and vendor benchmarking projects focused on identifying UVM industry trends and best practices. CNUC benchmark surveys have been used for presentations at major UVM conferences, discoverable information in rate cases, UVM program reviews, justifying budget requests, and as general knowledge in

decisions made in the day to day operations of our benchmarking subscribers UVM programs.

- CNUC has had direct involvement with the development, interpretation, and promulgation of numerous industry standards and regulations. This includes, but is not limited to, GO 95 Rule 35, NESC 218, PRC's 4293 and 4292, the Uniform Fire Code, the Urban/Wildland Interface Fire Code, FAC-003, and ANSI A300.

- Currently, CNUC is also directly involved with updating the NADF Tree Line USA criteria, and participating in changes to ANSI Z133.

- CNUC has presented at numerous national and international conferences on subjects ranging from "how trees cause power outages" to "customer service for the utility arborist".

- The CNUC leadership team who manages field activities has well over 50 years of combined experience in effectively providing services to the UVM industry.

The following CNUC people have participated in this project:

Steve Cieslewicz, President of CN Utility Consulting

Terry Mcgonegle, Senior Vice President

Will Porter, Senior Consultant

Nina Cohn, Analyst and Statistician

APPENDIX B – BENCHMARKING STUDY FRAMEWORK DETAILS

The following illustration is a detailed depiction of the Study Framework that was followed.

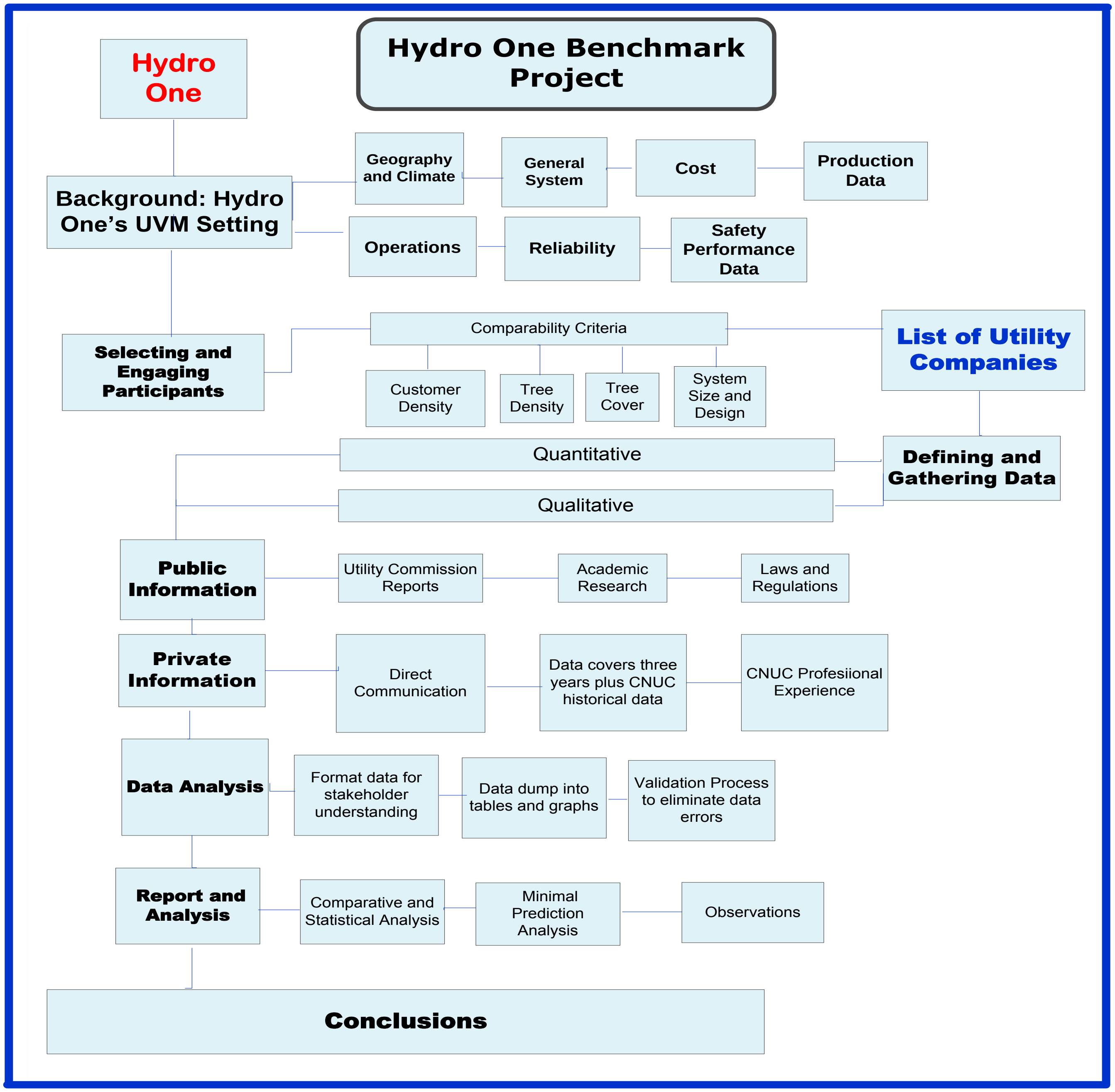
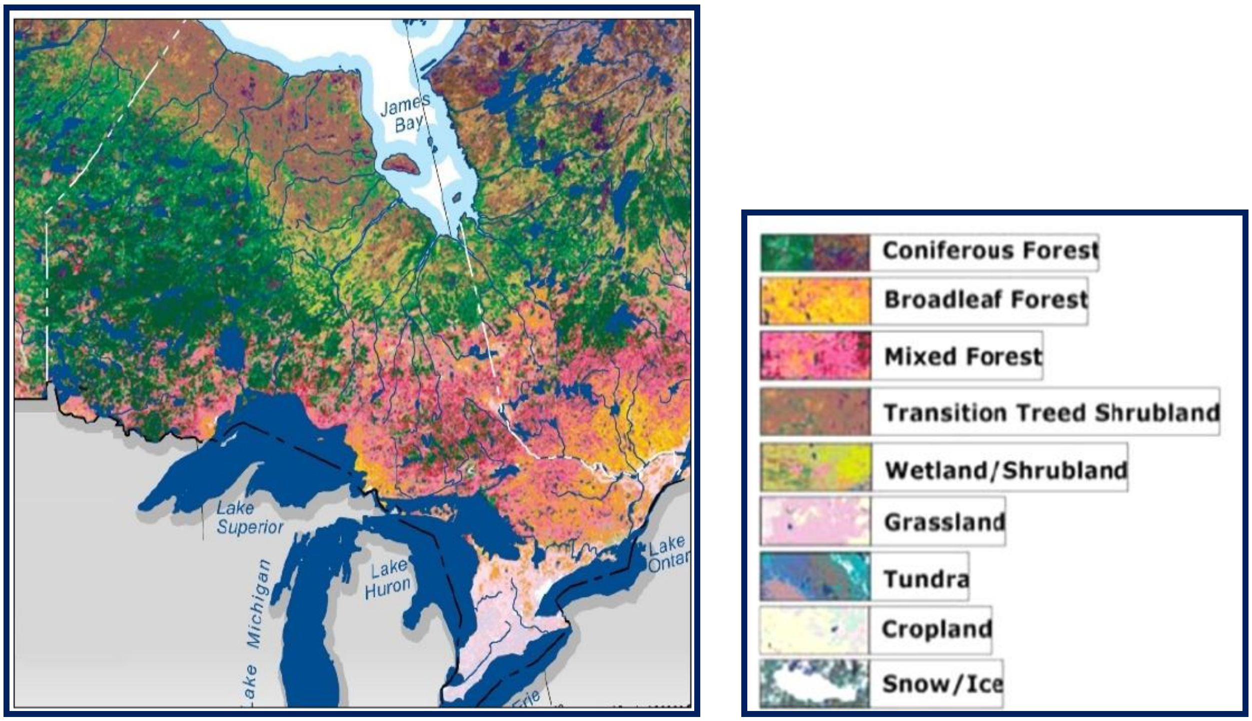


Chart 1 Benchmark Framework

APPENDIX C – HYDRO ONE BACKGROUND (VEGETATION; ZONES; WEATHER DETAILS)

C1. VEGETATION COVER

The following map (Map 1) illustrates the different types of vegetation cover in Ontario. The north is coniferous forest, while the central is mixed forest transitioning to broadleaf forest. The far south of the Province contains more grassland and cropland.

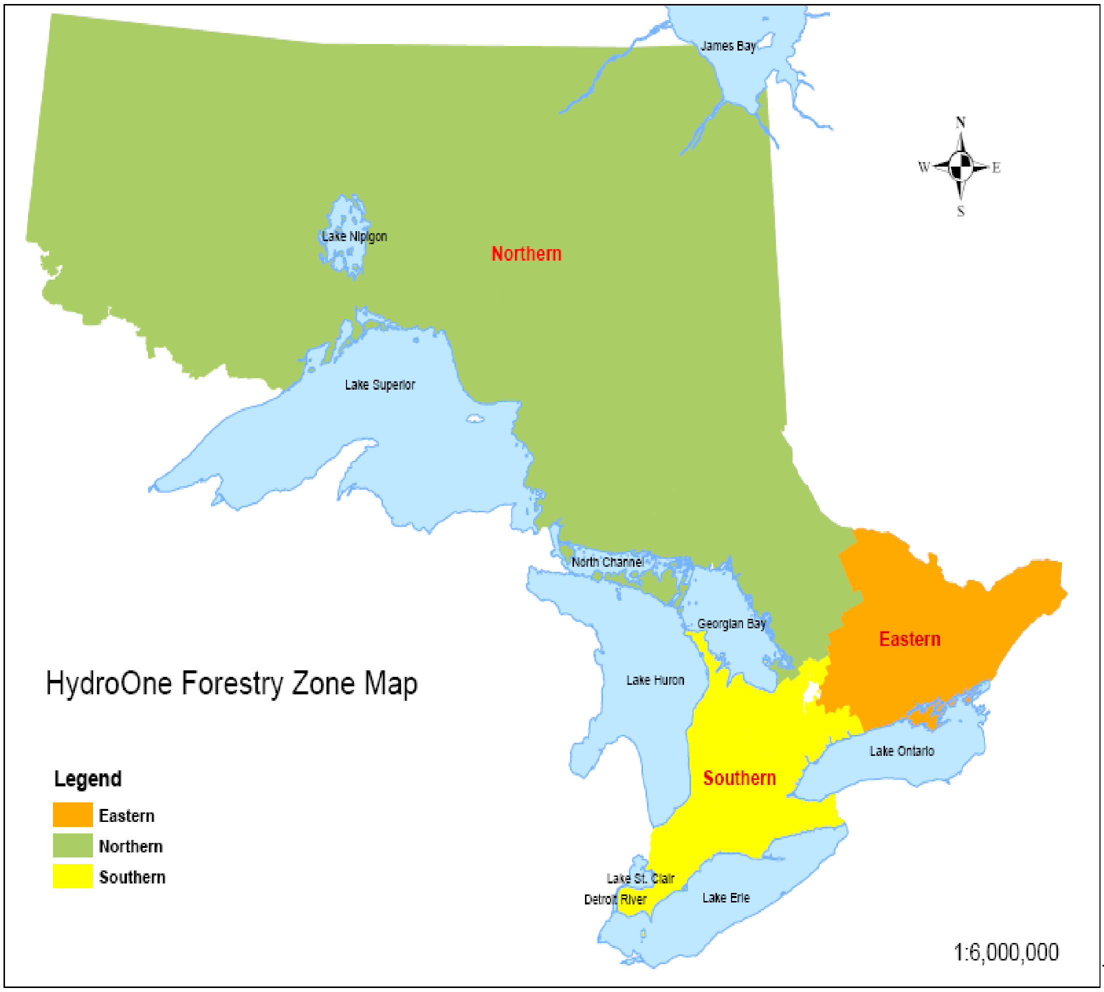


Map 1: Ontario Terrain – Forests, Shrublands, Cropland[6]

[6] Hydro One 2009

C2. Service Territory & Zones

To manage the vast and diverse territory, Hydro One's UVM operations are divided into three zones. The zones are illustrated in the Hydro One Forestry Zone Map below (Map 2).



[7]

Map 2 Hydro One Forestry Zones

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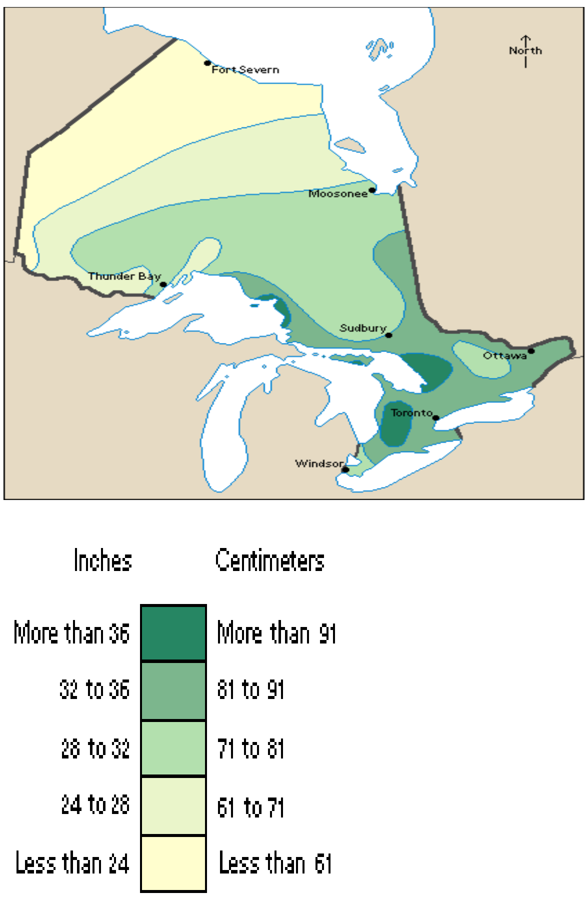
[7] Hydro One 2009

C3. Weather & Storm Events

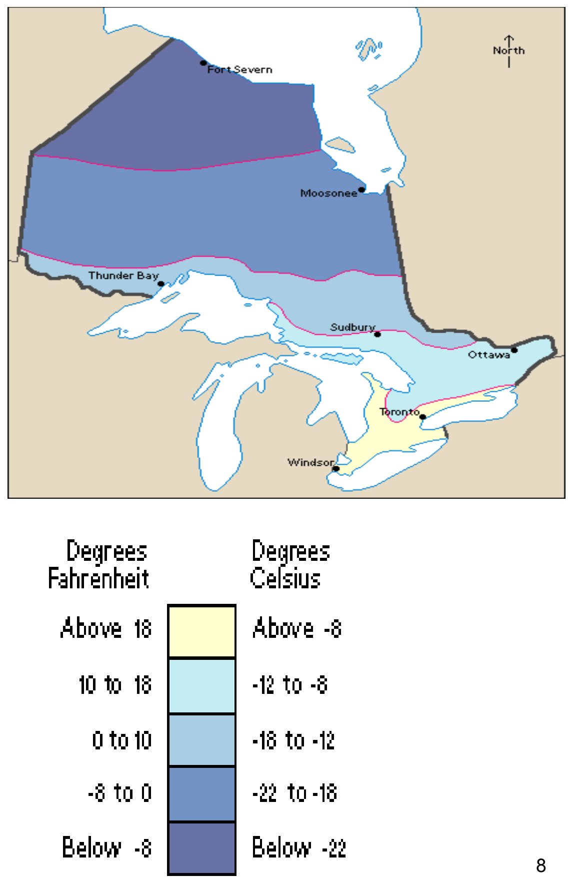
Given the vast territory of Ontario, different zones experience different weather and storm patterns and as a result different vegetation growing conditions and threats. Growing conditions are predominantly driven by precipitation and temperature. The following maps (Maps 3 and 4) provide details on yearly rainfall quantities and an example of temperature differences throughout Ontario using the month of January as an example.

Precipitation



Map 3: Average Yearly Precipitation

Temperature



[8]

Map 4: Average January Temperature Map

Based on the above charts, growing conditions are most favourable in the south and least favourable in the north.

[8] http://www.worldbook.com/wb/Students?content_spotlight/climates/north_american_climate

Of arguably greater importance than growing conditions are the storm patterns that are common to Ontario. Ontario is prone to wind, snow, and ice storms that disturb vegetation and impact power line facilities. Examples from recent years include the summer storms of July and August 2006 and the winter storm that hit during the last days of 2008. This most recent example in 2008 (Photo 1), saw winds of over 100 kilometres an hour cause widespread vegetation damage that resulted in more than 20% of Hydro One's customers being without power.

December 28, 2008 — *Hydro One crews have been battling a severe winter storm today, as winds of up to 100 km per hour topple hydro poles and road closures hamper assessment and restoration efforts. By 4 p.m. today, more than 230,000 customers were without power. Hydro One has mobilized resources from across the Company, as the storm has affected communities right across the province.*

Photo 1 [9]

The worst example of an ice event occurred in 1998, when Ontario experienced one the worst ice storms recorded in weather history.

> ***Ice*** *accumulations were estimated at over 100mm in some areas. Over 3 million hectares of forests and woodlots were damaged in eastern Ontario and southern Quebec. One of the hardest hit* ***areas*** *was that around Winchester, Ontario.*[10]

Outages during winter events are often difficult to access and repair and they are more dangerous when temperatures plummet after the icing event, prolonging the storm and its damaging effects. A key reliability objective in Hydro One's UVM program is geared towards preventing outages from storm events:

> *Vegetation is managed to protect against both falling trees and wind or snow induced line contact.*[11]

[9] http://maplelakeontario.com/2009/01/06/power-is-back-on-for-most-in-southern-ontario-outage-map/

[10] "Post-Ice Storm Tree Damage In Four Eastern Ontario Woodlots" by Jennifer Kelly-Syrota, (2000) University of Toronto.

[11] Vegetation Management Benchmarking and Density/Cost Allocation Studies Prepared for: Hydro One Networks Inc. Stakeholder Consultation Meeting Notes. (April 2009)

APPENDIX D - SELECTING PEER UTILITIES (COMPARABILITY CRITERIA)

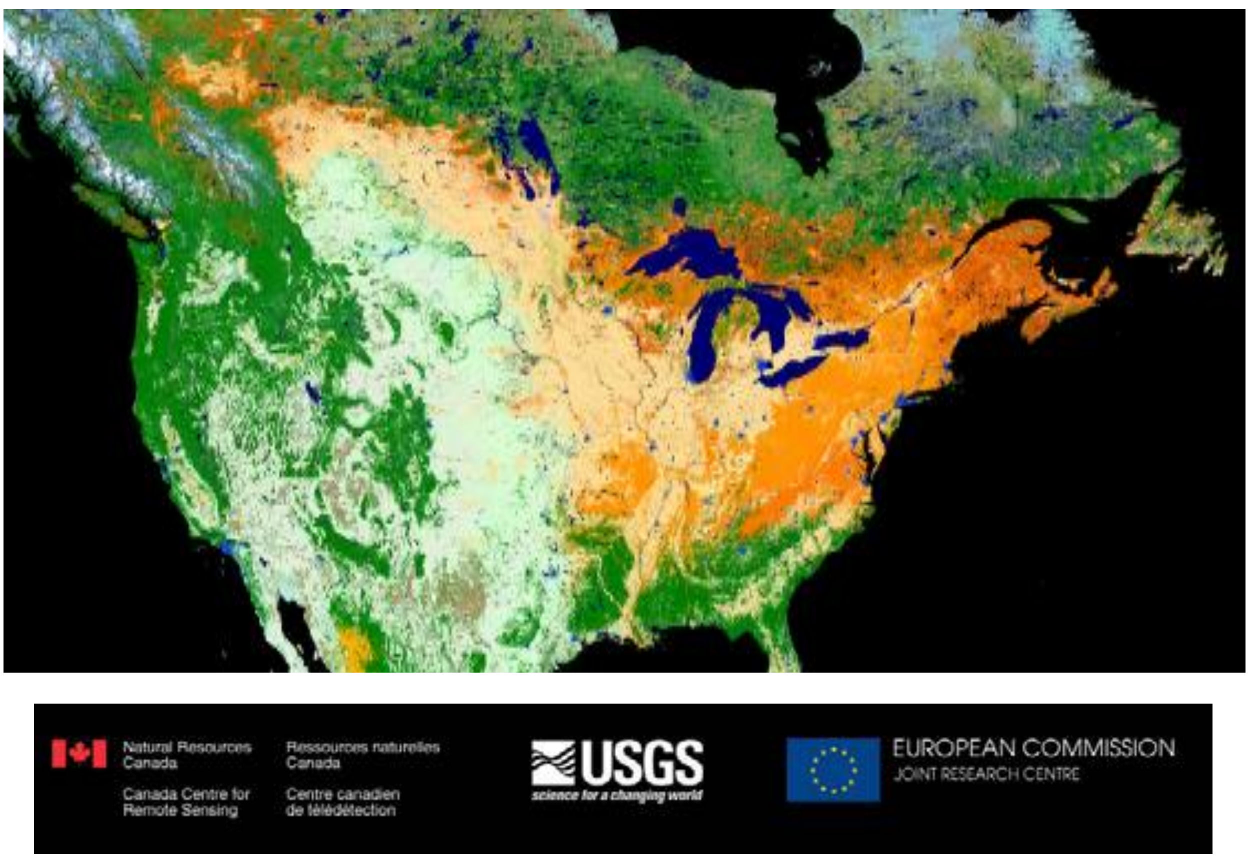
The selection of peer utilities to be included in the study was based on comparability criteria as follows:

1) Vegetation Cover & Density
2) Weather Considerations (e.g. Vegetation Growth Considerations & Storm Paths &)
3) Distribution System Characteristics (i.e. Customer Density; Size of Service Territory; Percentage of Overhead Lines and Off-Road Lines)

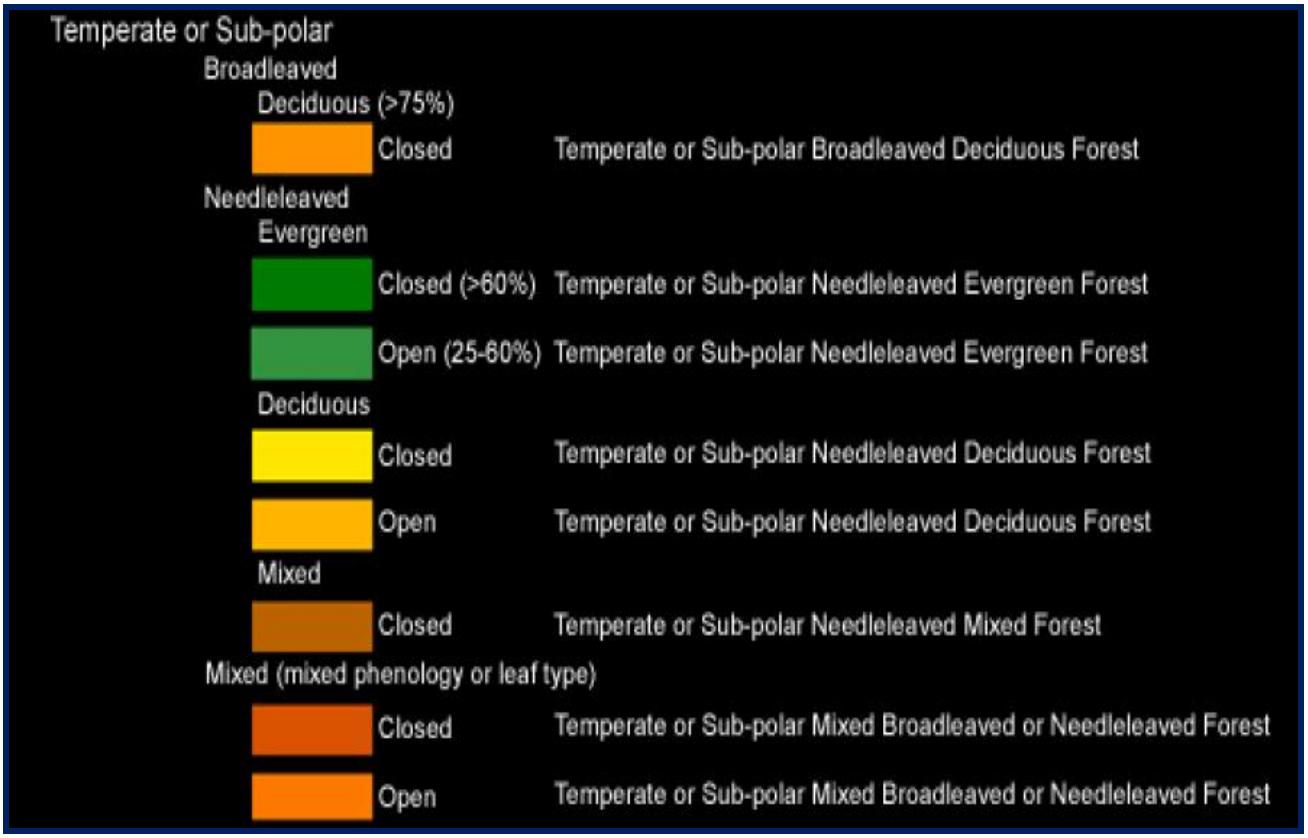
The following discusses the development of each of the comparability criteria.

D1. VEGETATION COVER & DENSITY

The following maps (Maps 5 and 6) illustrate various vegetation cover and density parameters that are important for comparability.



Map 5: USGS Forest Density & Type



Forest Legend for Map 5

Map 6: **NASA Earth Observations** **Vegetation Index [NDVI]** **(1 month Terra/MODIS)** June 1, 2009 00:00 - July 1, 2009 00:

Vegetation cover and density is of critical importance when benchmarking UVM programs as it is arguably the single biggest driver of costs. Hydro One has a very dense service territory with respect to trees and is among the top companies in the survey in this regard. The average density of trees per kilometre will affect the average cost per managed kilometre. Knowing the relative tree densities between companies will allow for more accurate comparisons with respect to efficiency measures associated with labour hours and costs.

Based on the above maps, the first comparability criterion used in the study was that peer utilities should be located in vegetation cover that is:

- **Around Ontario**
- **Northeast or northwest North America**
- **The denser areas of the southern United States**

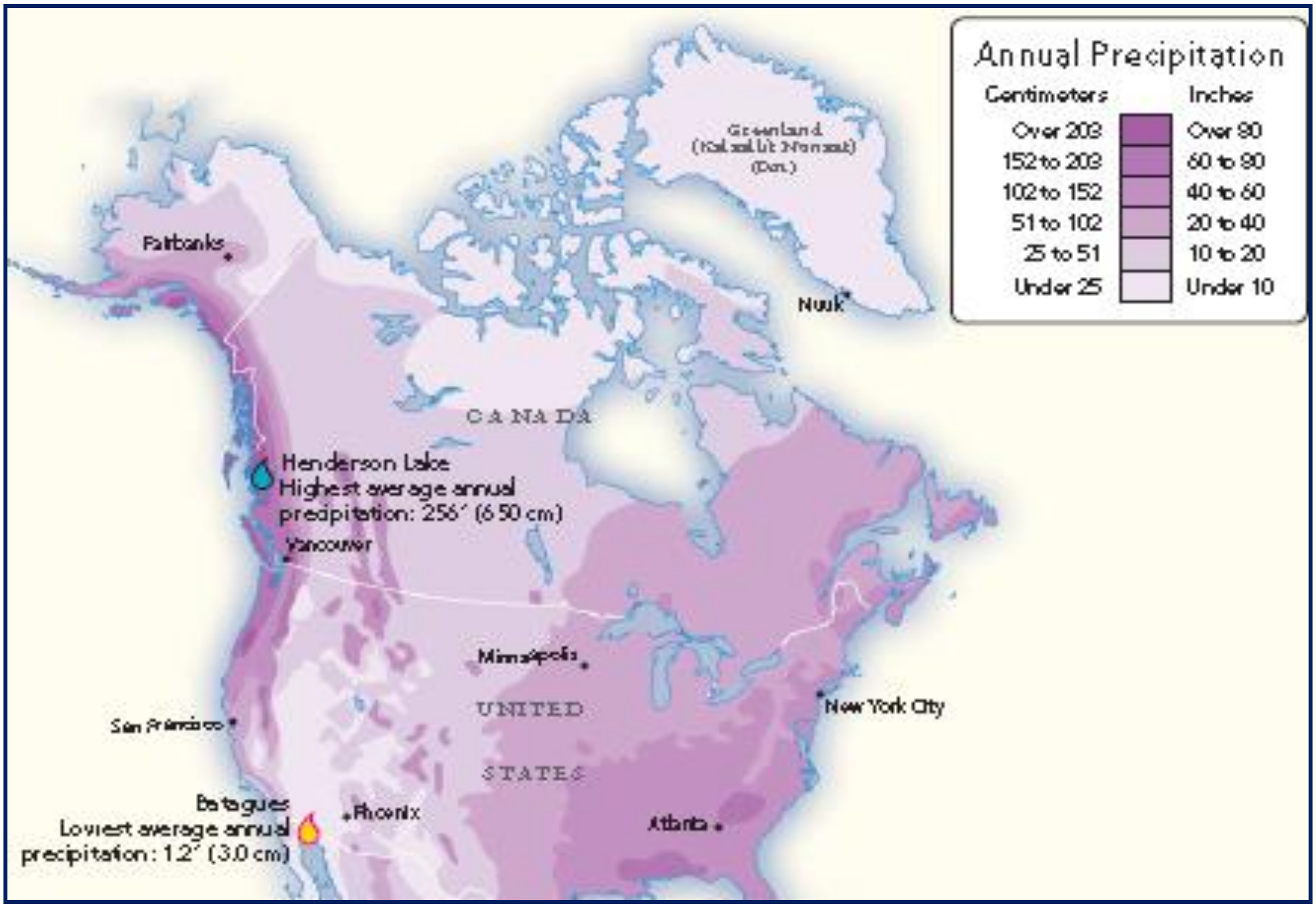
The objective of the above criterion was to identify locations that are comparable although it is accepted that they will not necessarily be identical. Other factors such as type of terrain or specific vegetation will impact comparability and CNUC understands that these differences are very challenging to normalize for in practice. Hydro One's varied service territory, while not identical to all peer utilities in this study is comparable. For example, although Hydro One does not have the terrain of the mountains or the high precipitation of the northern pacific coastal areas, or the long growing seasons of southern US, it does have many areas impeded by water bodies, steep terrain, and very difficult temperature extremes that arborists must negotiate during much of the year. Despite these differences, the presence of common vegetation species and densities makes utilities comparable for the purposes of this study. (E.g. The spruce, pines, firs and aspens common to the conifer and mixed wood forests in Ontario are also the same genus found in the Rocky Mountains, the Sierras of the west coast states and the northern US states south of Lake Superior. The mixed wood forests and deciduous forests of eastern United States vary more in genus-species diversity, but the size and density of forests are comparable to those of southern and eastern Ontario.)

D2. Weather & Storm Characteristics

Weather (i.e. precipitation and temperature) and storm characteristics (i.e. wind, ice, snow) of a utility's territory play a significant role in UVM programs as they impact the type and growth rate of vegetation and establish a need for storm hardening of a distribution system. As a result, it is necessary to consider weather and storm related criteria when assessing the comparability of utilities for UVM benchmarking purposes.For vegetation growth, precipitation and temperature are the key drivers.

In comparison to other regions of North America, Ontario has higher than the average precipitation, which stimulates vegetation growth. Typical ranges of precipitation in North

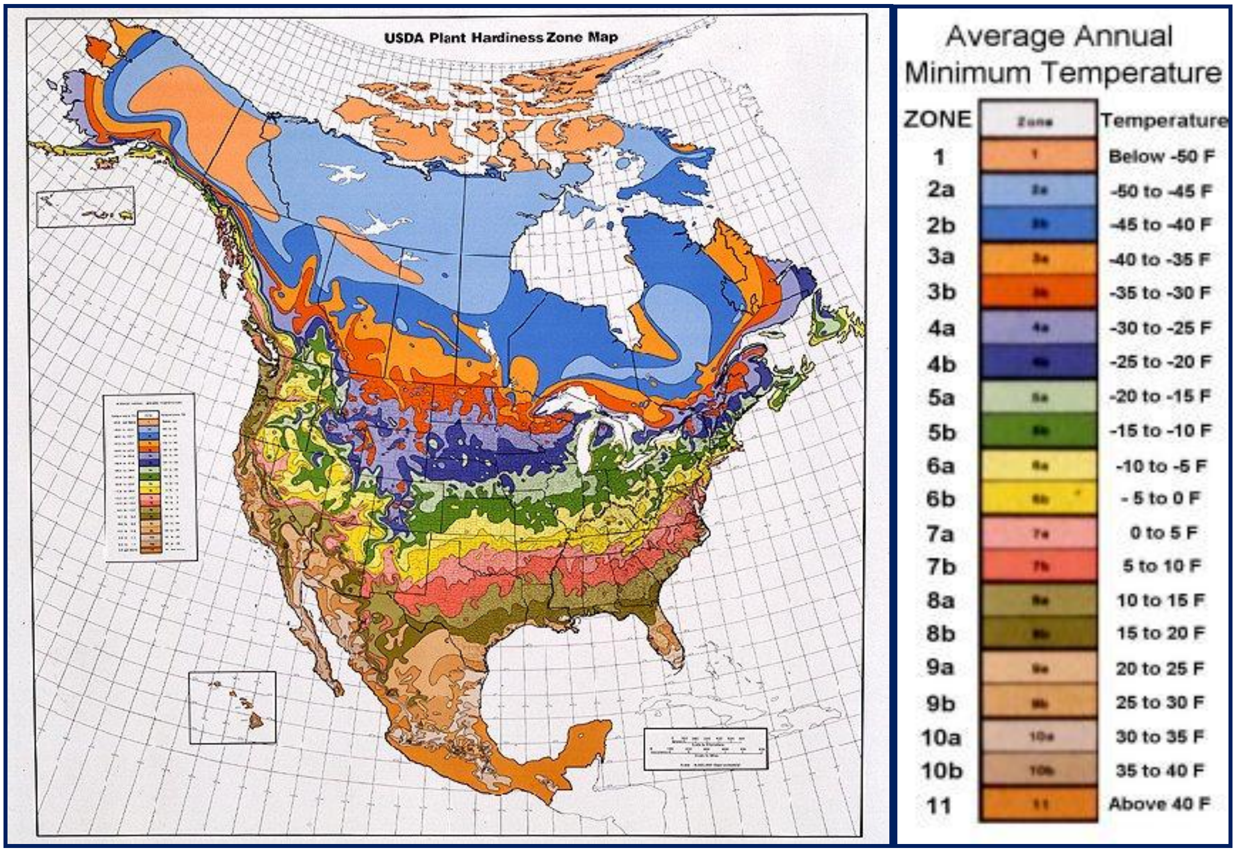
America typically vary from over 200 cm a year in northwestern parts of the continent, to less than 30 cm in parts of the southern US as depicted by the chart below (Map 7).



Map 7 North American Precipitation Map[12]

In terms of temperature, Ontario is colder than most other regions of North America and this factor results in a shorter growing season. This is illustrated in the map below (Map 8), which compares "Plant Hardiness" zones for North America on the basis of temperature.

[12] http://maps.howstuffworks.com/north-america-annual-precipitation-map.htm



Map 8 North American Average Annual Minimum temperature[13]

Simplistically speaking, the combination of precipitation and temperature drive vegetation growing conditions. To examine the growing conditions of North America, the "Potential Biomass" for the continent can be examined. "Potential Biomass" is defined as the amount of plant biomass that can be accumulated in one year under the assumption of ideal conditions prevailing for photosynthesis (i.e. absorption of solar energy by plants and storage of the energy as plant material). The map given illustrates the output for Potential Biomass.[14]

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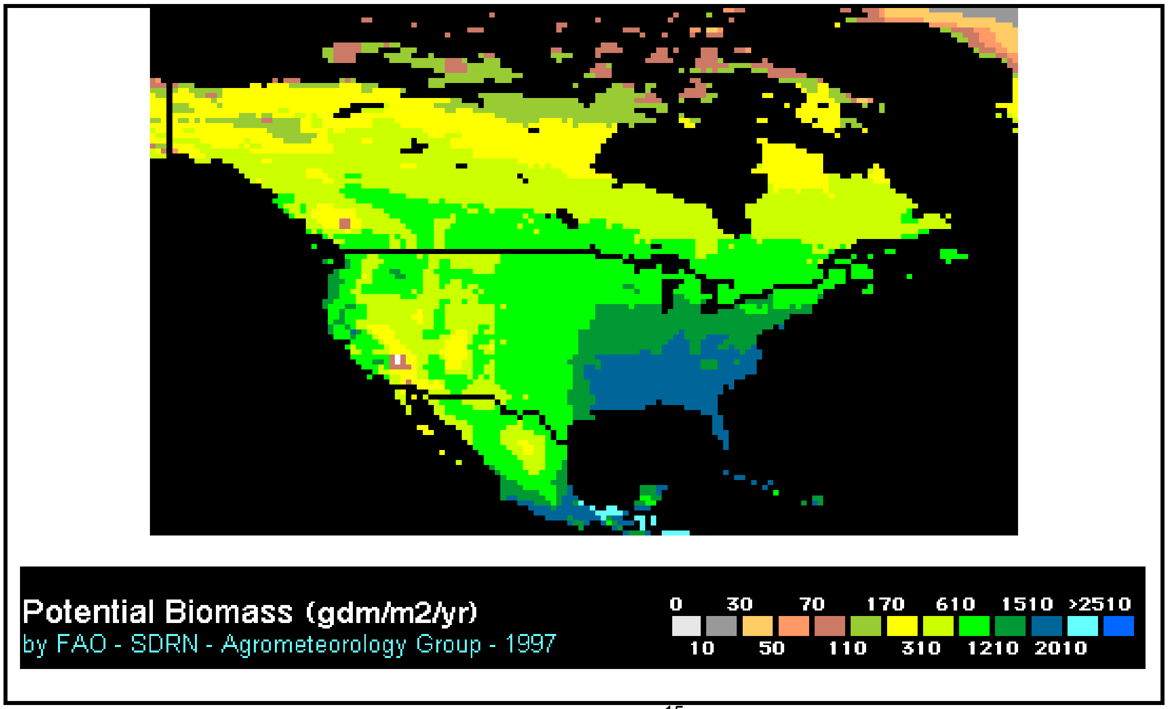
[13] http://www.usna.usda.gov/Hardzone/ushzmap.html

[14] Lieth, H., 1972. "Modeling the primary productivity of the earth. Nature and resources", UNESCO, VIII, 2:5-10.



Map 9 North American Potential Annual Biomass Accumulations[15]

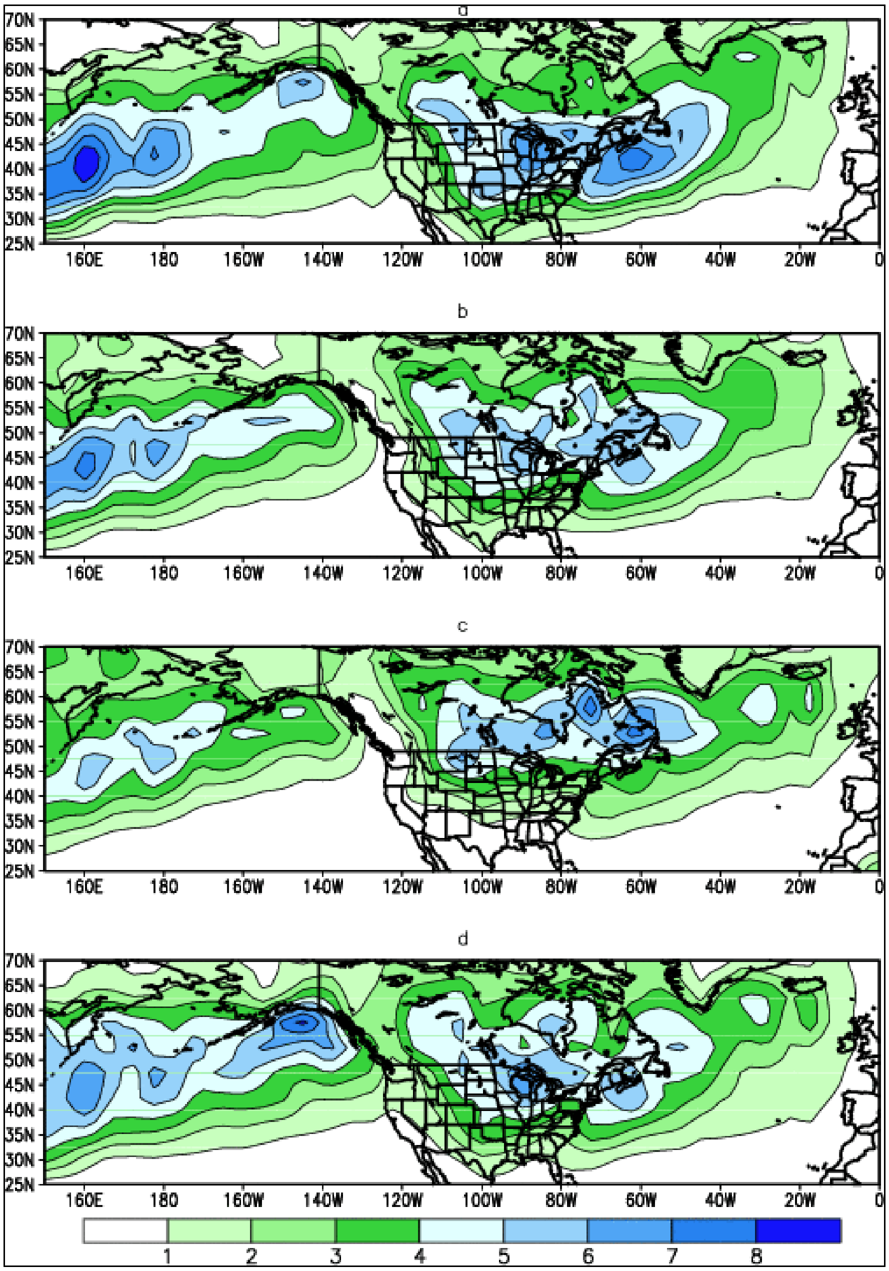
This illustration elegantly summarizes the maze of various factors associated with comparing vegetation workloads (i.e. precipitation, average minimum temperature, days of sunshine, soil characteristics, days of wind and wind velocity, age of forest and human activity). Although Ontario has a shorter growing season, and less rainfall than other regions in North America, the map shows that it has comparable growing conditions to many regions in North America. Based on it, the most comparable conditions for vegetation growth are the areas around Ontario and those, along the north central and northeastern parts of the United States.

Turning attention directly to storm activity, the following charts illustrate storm frequency and the common storm paths that occur in North America.

[15] Lieth, H., 1972. "Modeling the primary productivity of the earth. Nature and resources", UNESCO, VIII, 2:5-10.

Storm Track Climatology

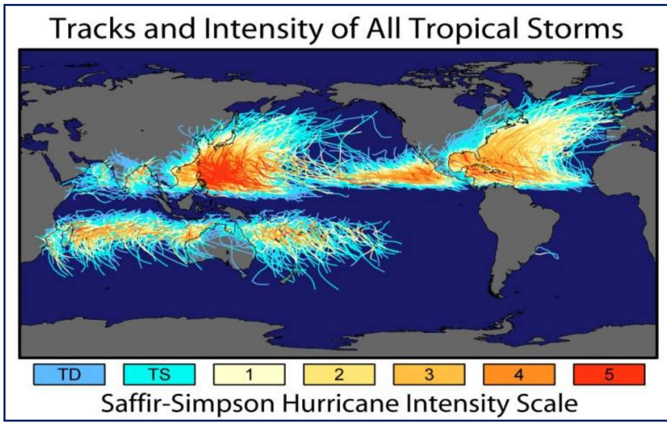
Average seasonal frequency of storms for (a) winter, (b) spring, (c) summer, and (d) fall. The frequencies are calculated from the 1950-2002 time period.

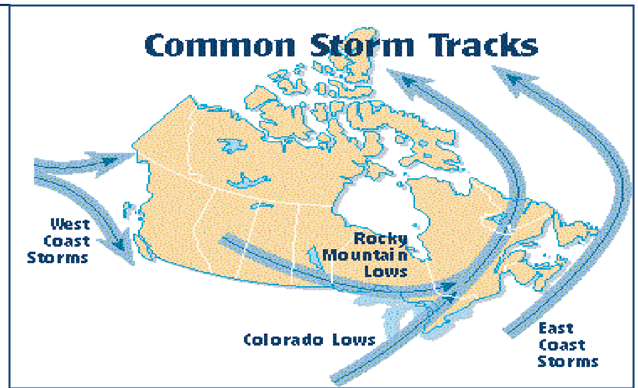


Map 10 North American Seasonal Storm Tracks

Image Courtesy of NOAA[16]*NOAA/ National Weather Service*
National Centers for Environmental Prediction Climate Prediction Center

[16] Earth Gauge http://www.earthgauge.net/wp-content/CF_Storm%20Tracks.pdf, National Environmental Education Program.





Map 12 in North America[17]

Map 11 Storm Tracks Worldwide

The above maps (Maps 11 and 12) illustrate that Ontario and the northcentral and northeastern US have a greater storm frequency that other parts of the continent. In terms of storm tracks, the east coast is impacted by events in the Atlantic Ocean and is routinely faced with wind events, particularly in the "Hurricane" season when tropical storms are common. The central part of the continent is typically impacted by one of either the Rocky Mountain Lows or the Colorado Lows. Ontario and in particular the central part of the Province is "fortunate" to be impacted by both of these storm tracks. The west coast is impacted by storms eminating from the Pacific Ocean and is also subject to tropical storms. When comparing utilities from a UVM perspective and assessing the need to "storm harden" a system, the most comparable utilities would lie in regions that are frequently impacted by storms.

Based on the above maps and discussion, the second comparability criterion used in the study was that peer utilities should be exposed to similar weather (i.e. vegetation growing conditions) and storm tracks. Preferred locations are:

- **Around Ontario or;**
- **North central and Northeastern North America or;**
- **Western or Southern areas impacted by common storm tracks.**

As stated earlier for other comparability criteria, the objective is to select utilities that are in locations that experience comparable weather conditions, although it is understood that the conditions will not be identical. In the case of storms, Ontario is in the centre of a high storm activity zone in the North America and it is also on the path of two major storm tracks, both of which are conditions not necessarily experienced by peer utilities.

[17] PA Consulting "Hydro One Distribution Benchmarking Study " 2007

D3. Customer Density – Rural Attributes

The final comparability criterion was related to how rural a utility's service territory is as measured by customer density (i.e. number of customers per kilometre), Hydro One is unique in North America as it has a very low customer density throughout its extremely large service territory and its three forestry zones. The importance of this is that Hydro One UVM staff must travel many kilometres to manage vegetation, with fewer settlements, fewer roads and great accessibility challenges. The rural nature of the service territory necessitates Hydro One crews to travel greater distances between work areas as well as greater distances from their homes. Companies that are not rural in nature have sufficient kilometres of line in a geographic area to require full time crews that seldom travel and lodge away from home. In addition to the travel considerations, UVM programs in rural territorities are impacted by the fact that they are naturally vegetated as opposed to urban locals where overall vegetation density is controlled and reduced as a result roads, buildings, and other infrastructure that exists in more urban and populated areas.

Previous benchmarking studies (i.e. PA Consulting 2007) set a comparability criteria of 30 customers per kilometre. For this study, CNUC used the same customer density threshold (i.e. 30 customers per kilometre) as a criterion to guide utility selection for the purposes of "rural" comparability.

It should be noted that a number of other measurements can be used to assess the rural nature of a utility. Some of these include measures using the size of a utility's service territory, the percentage of underground lines, and the number of multi-circuit lines, to name a few. CNUC did collect information on these measures, and this information is contained in the first section in Appendix E.

Appendix E: Graphs and Chart Supplement

E.I. General and System Information

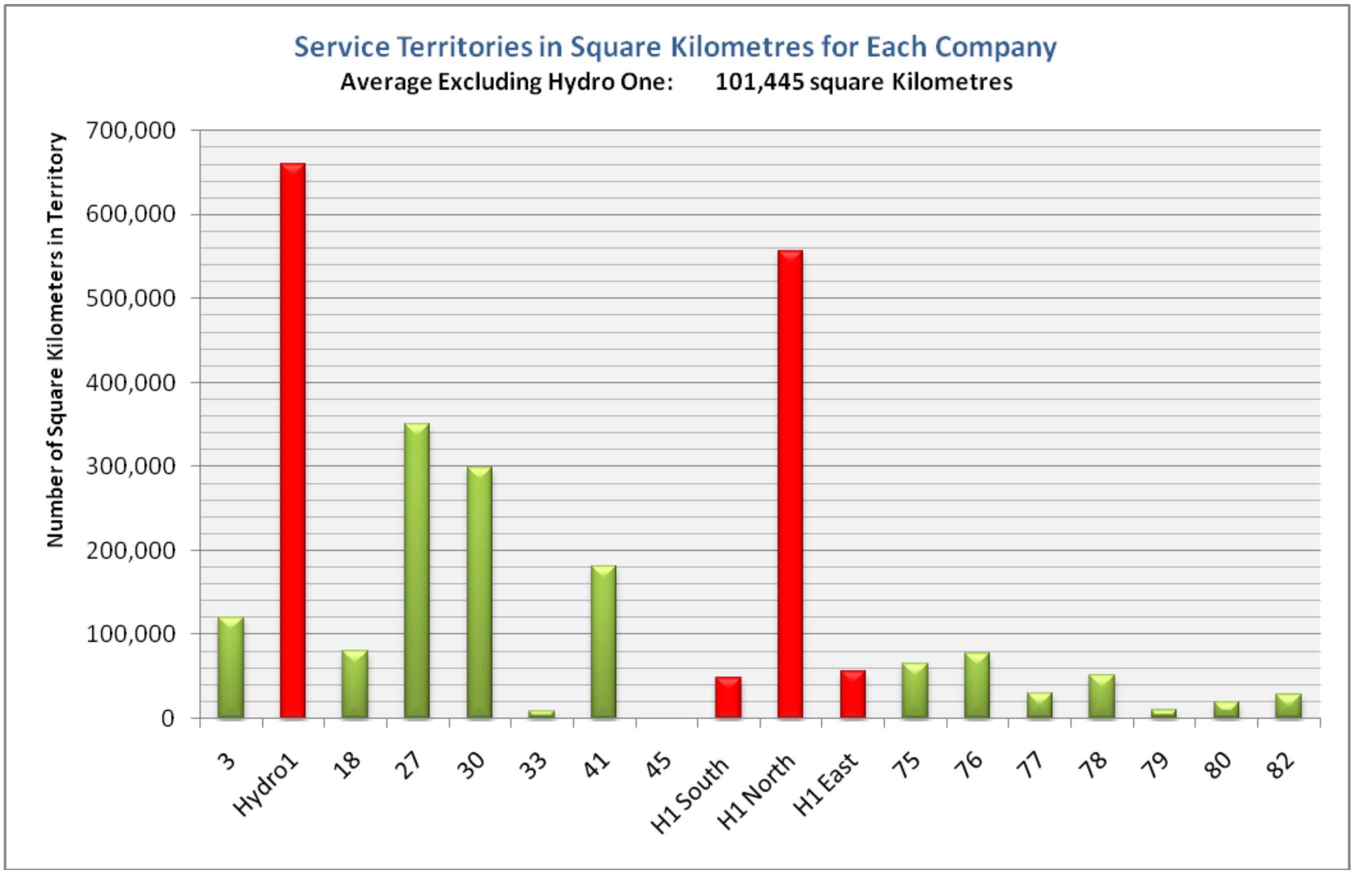


Figure 1: Service Territories for Each Company

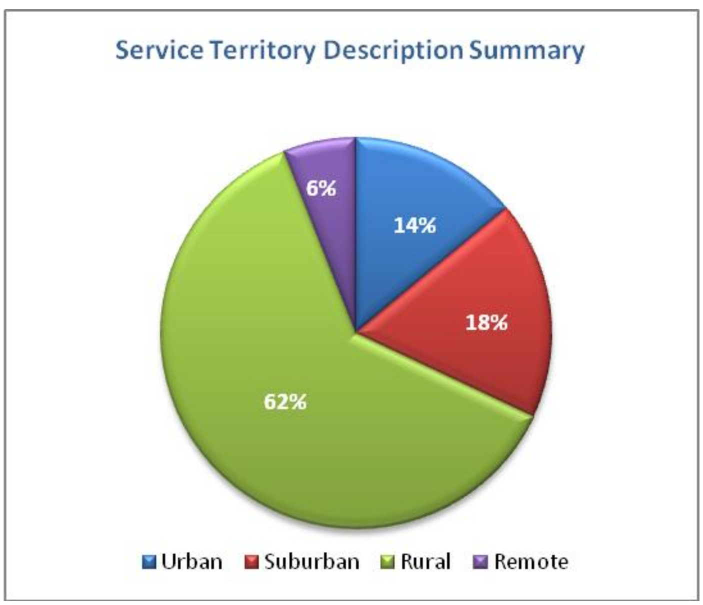


Figure 2: Territory Description

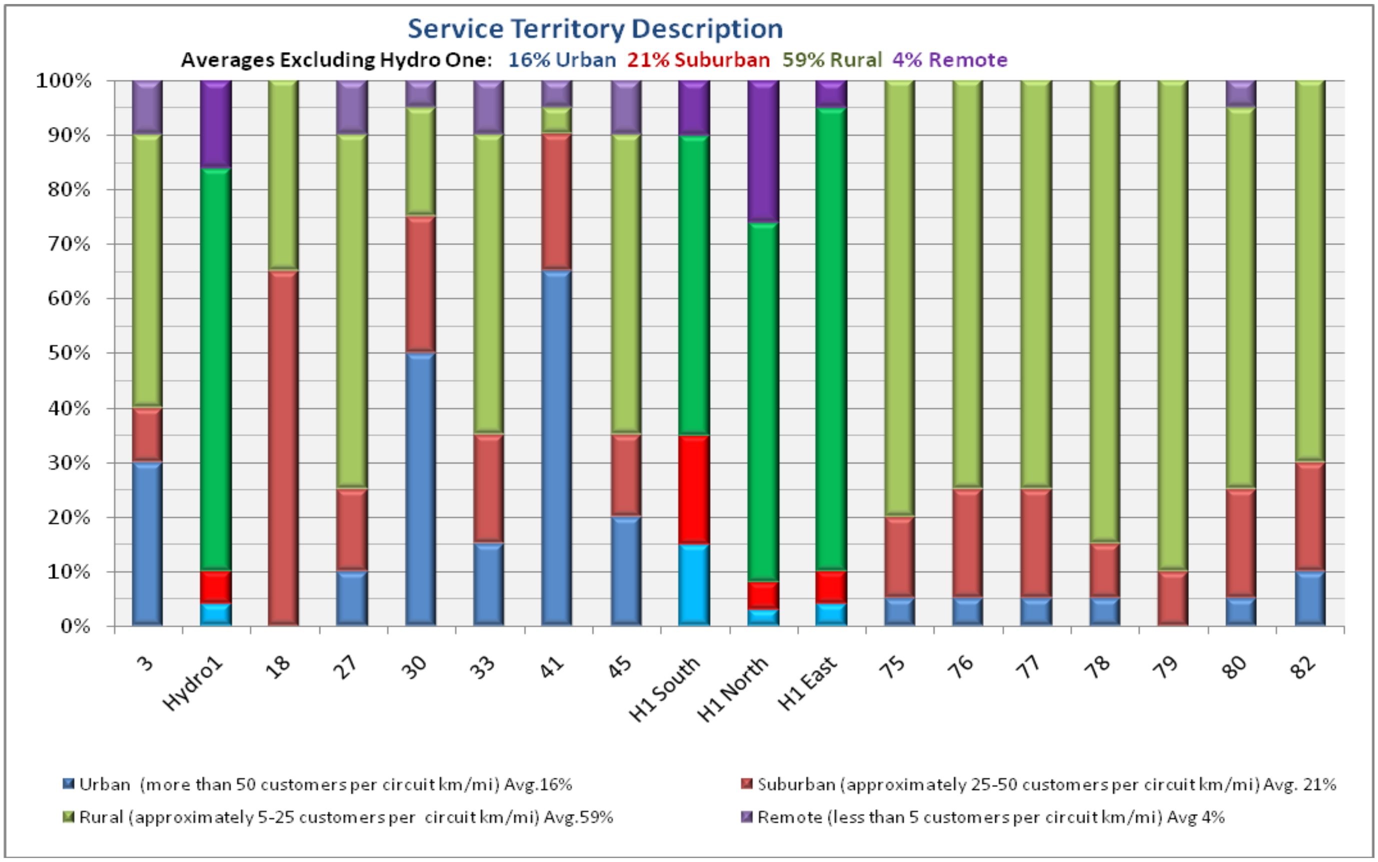


Figure 3: Service Territory Description

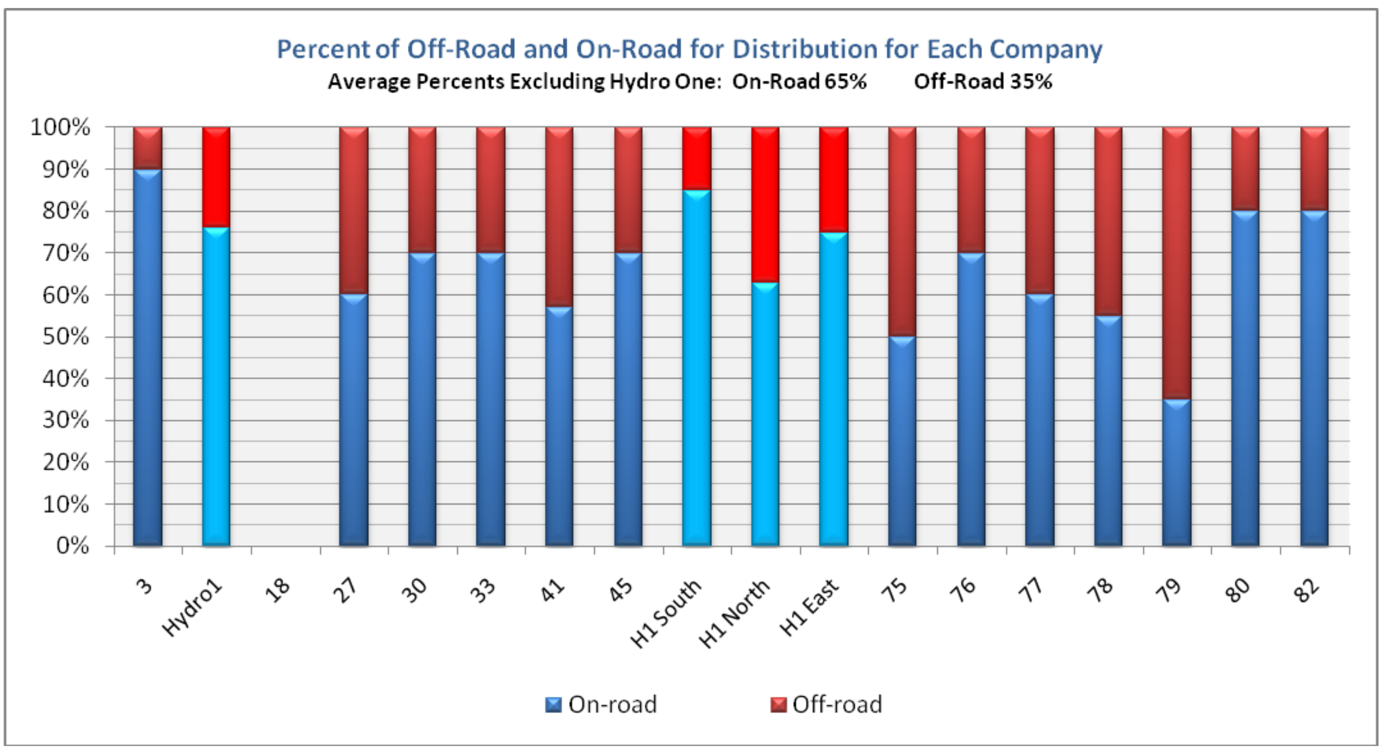


Figure 4: Percent of Off-Road and On-Road for Each Company

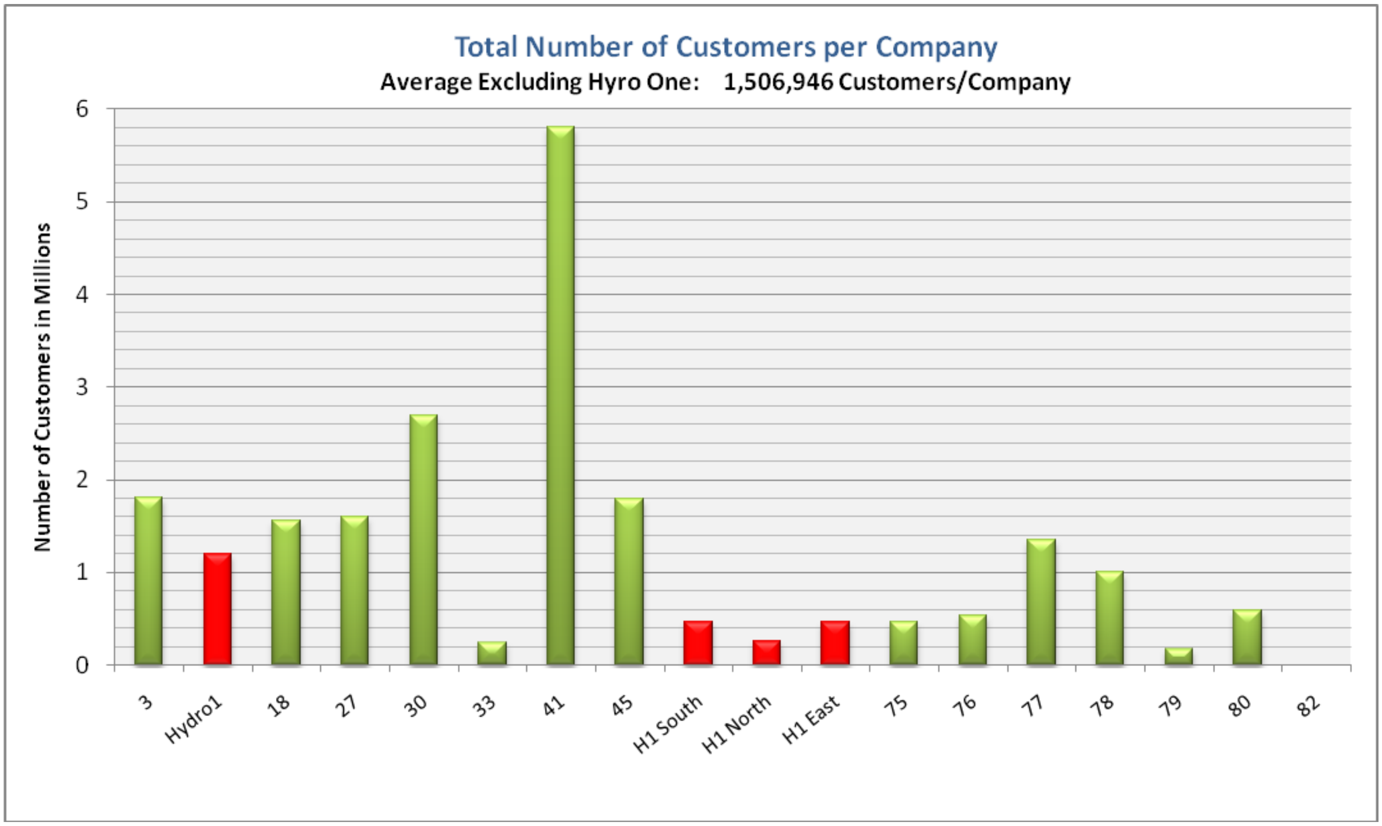


Figure 5: Number of Customers per Company

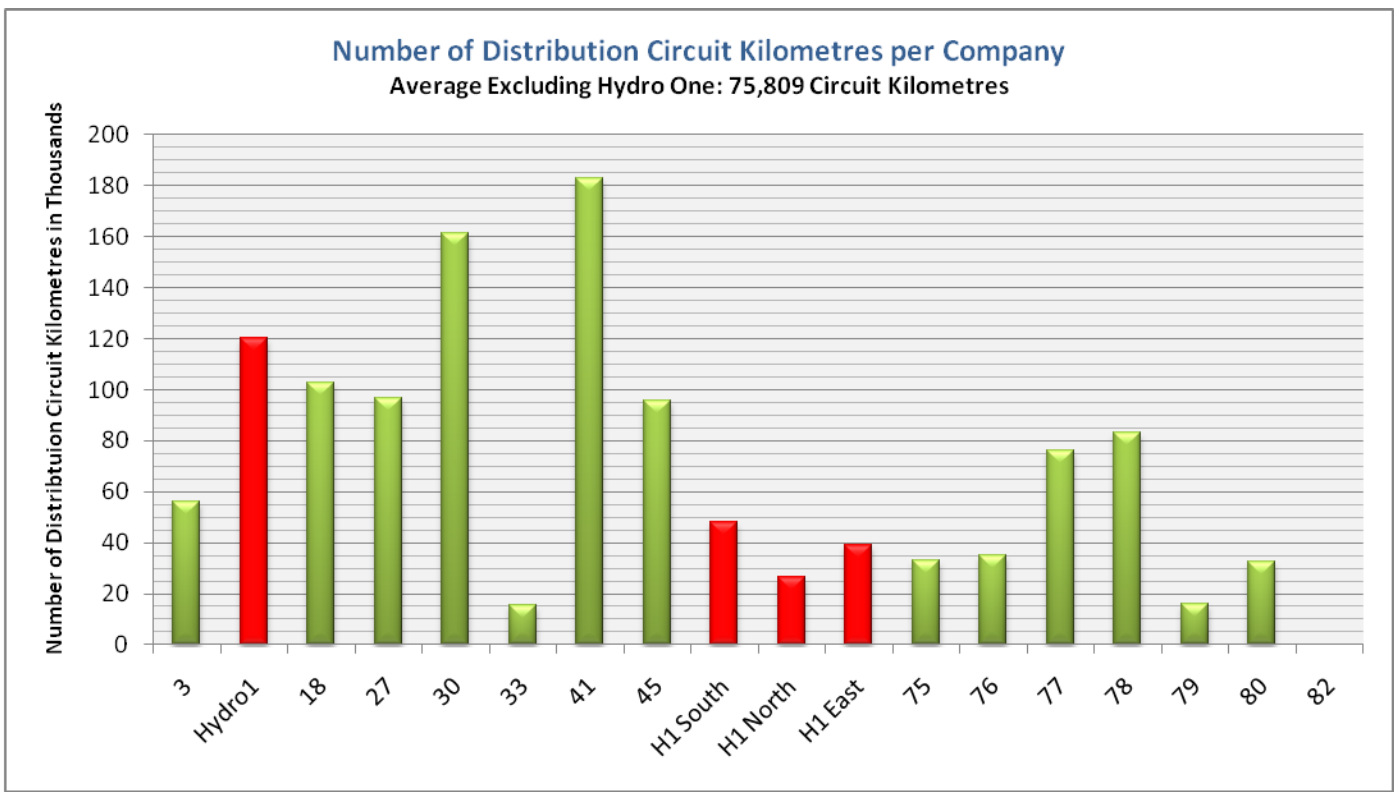


Figure 6: Number of Circuit Kilometres per Company

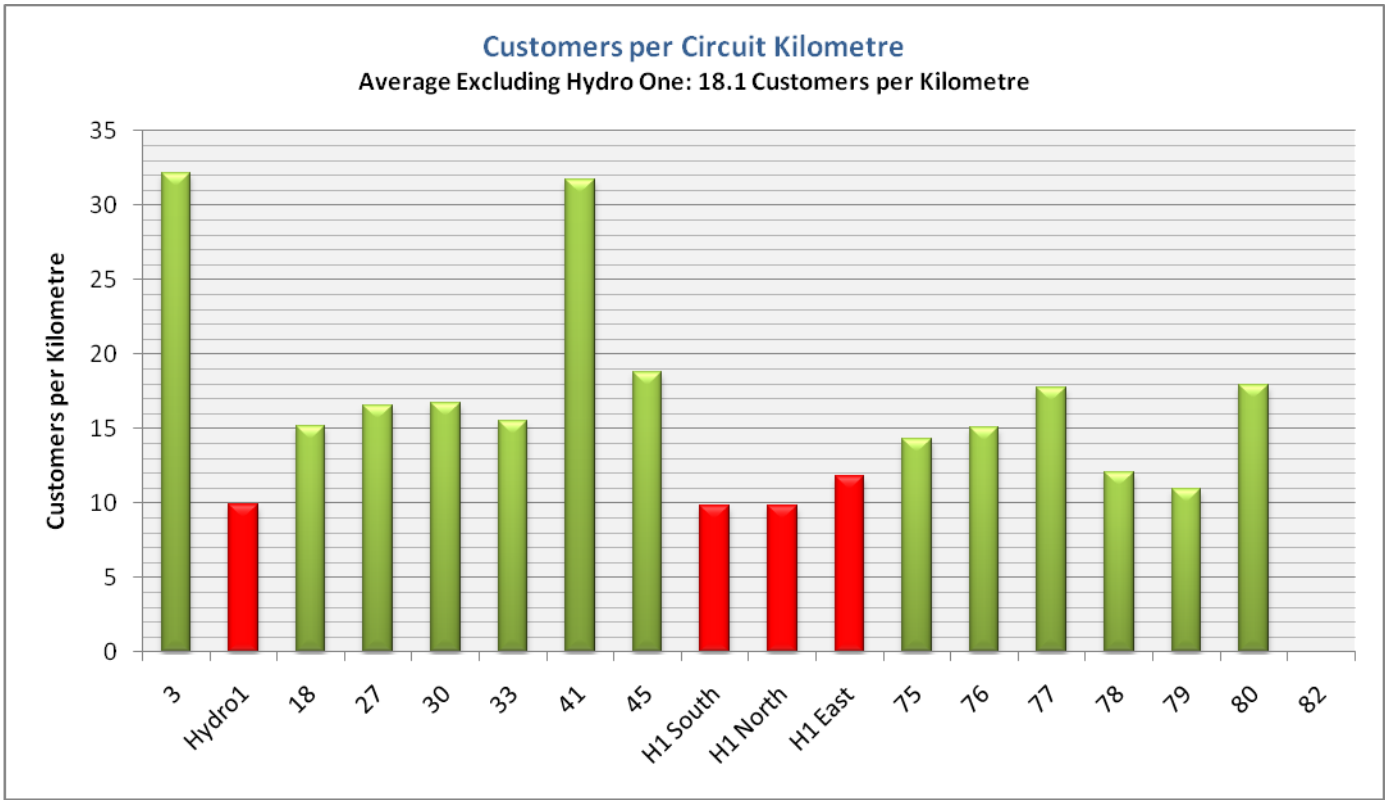


Figure 7: Customers per Circuit Kilometres

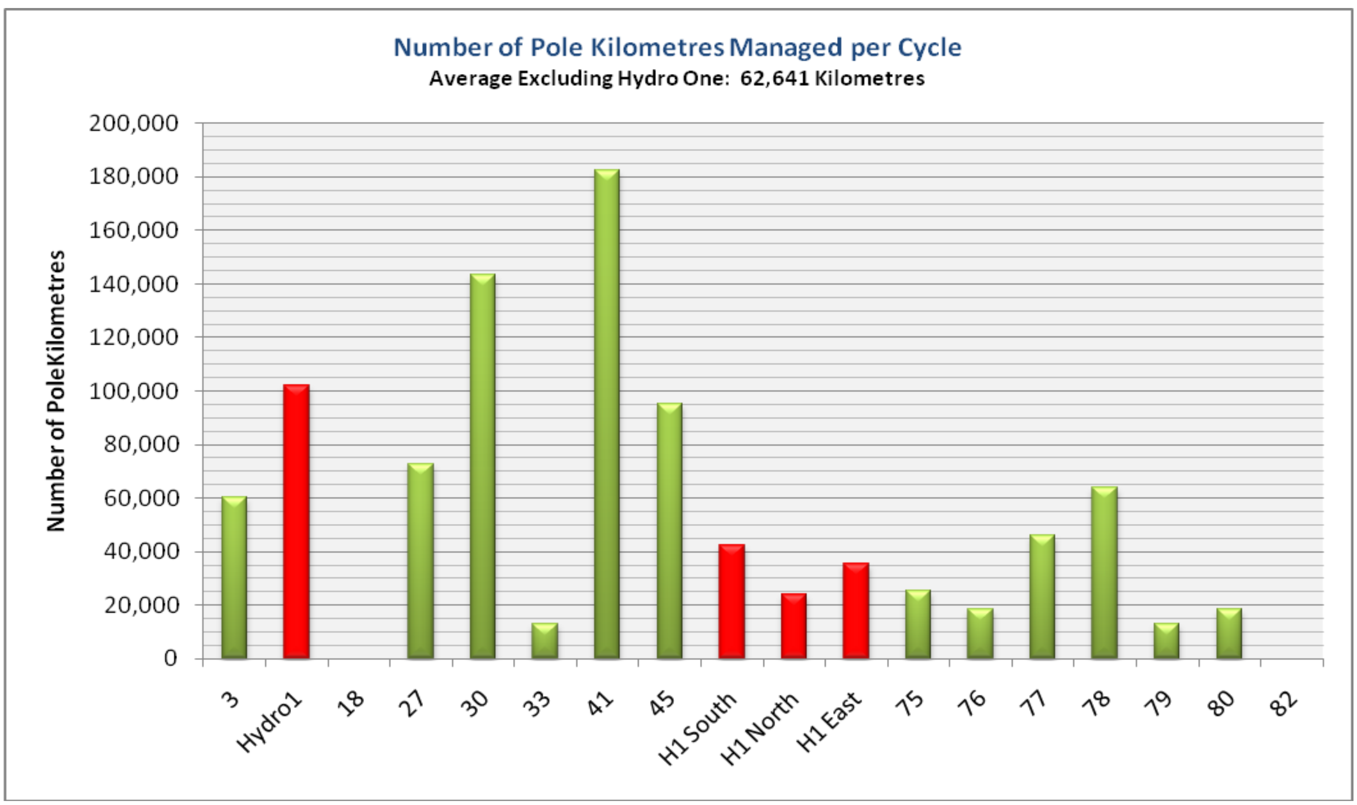


Figure 8: Number of Pole Kilometres Managed per Cycle

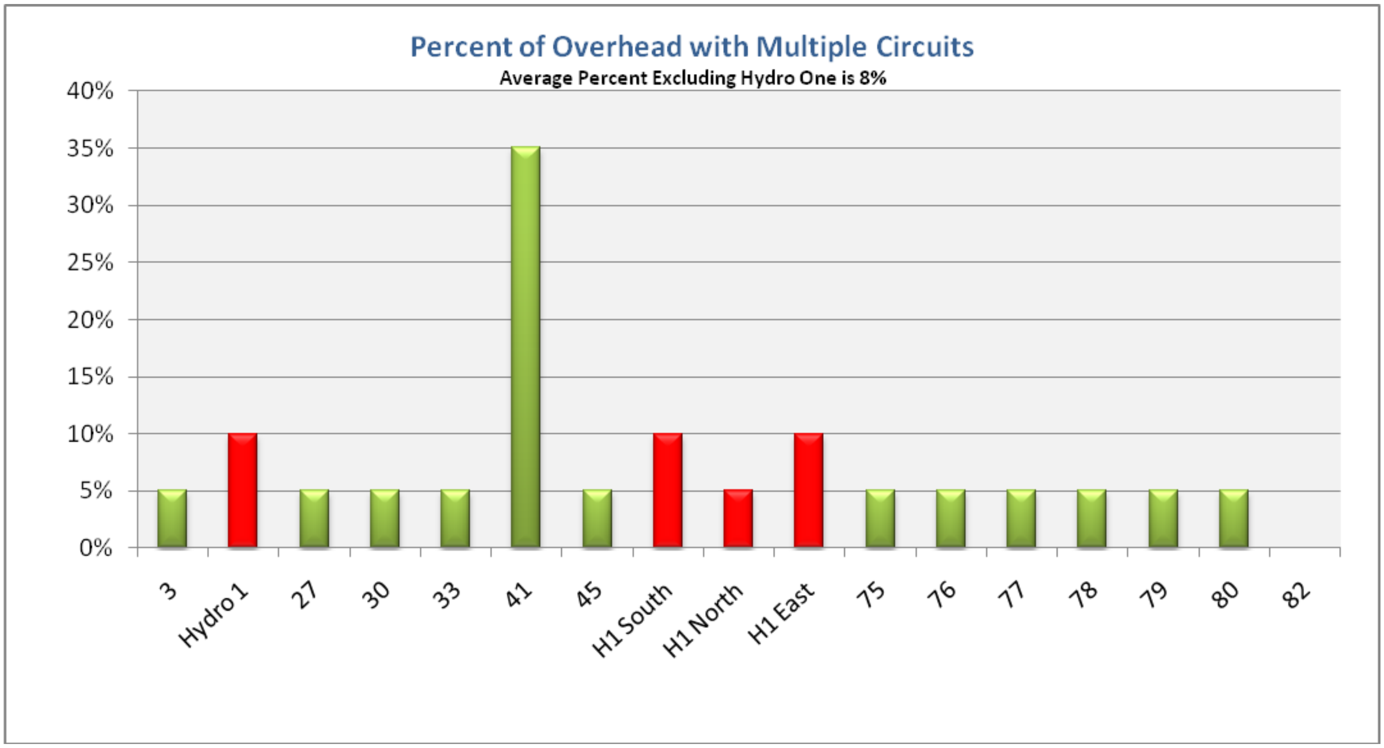


Figure 9: Percent of Overhead with Multiple Circuits

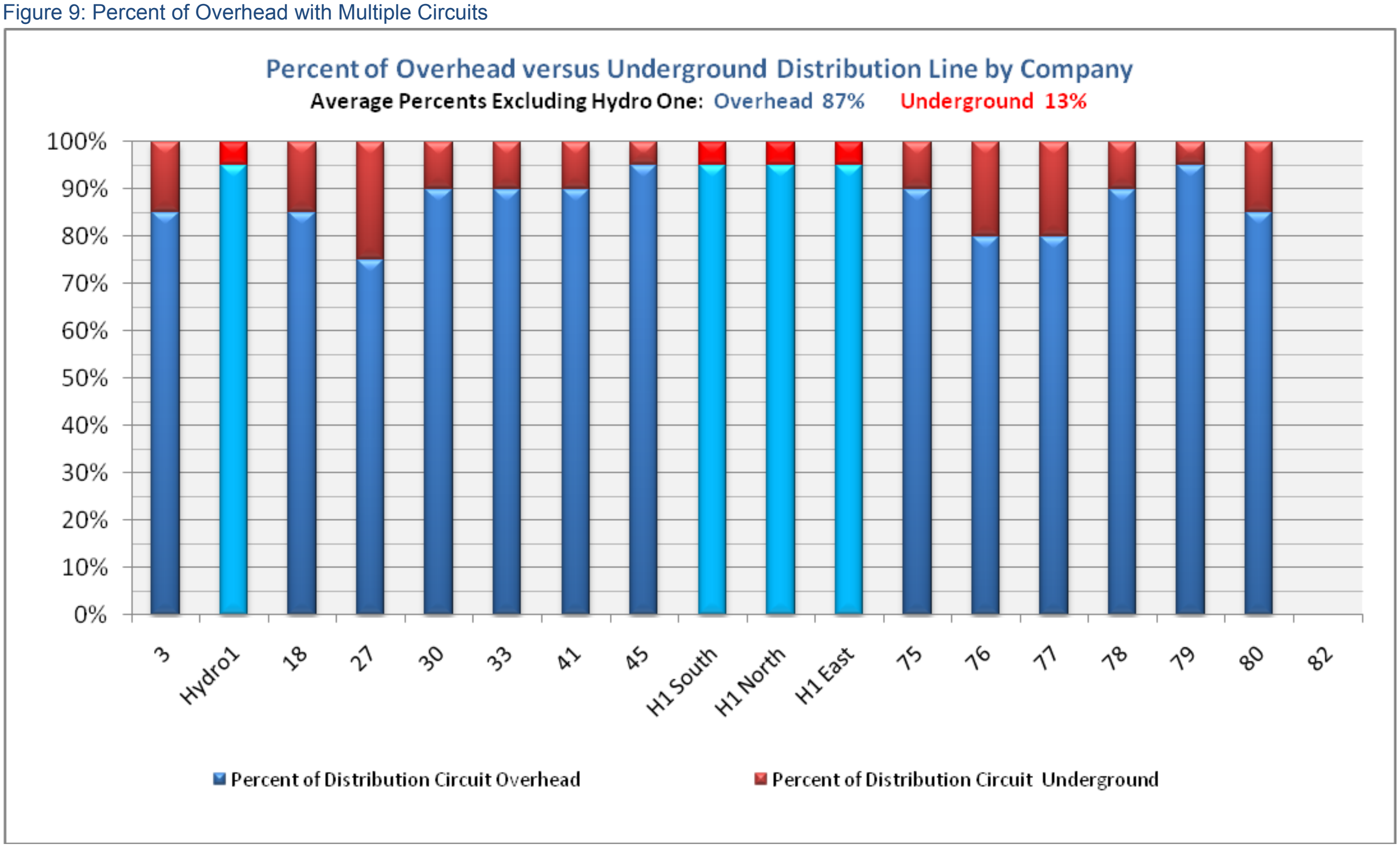


Figure 10: Percent of Overhead versus Underground Distribution Line by Company

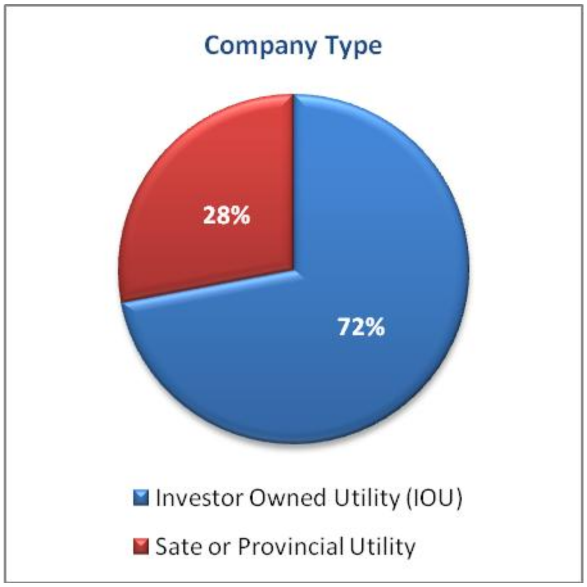


Figure 11: Company Type

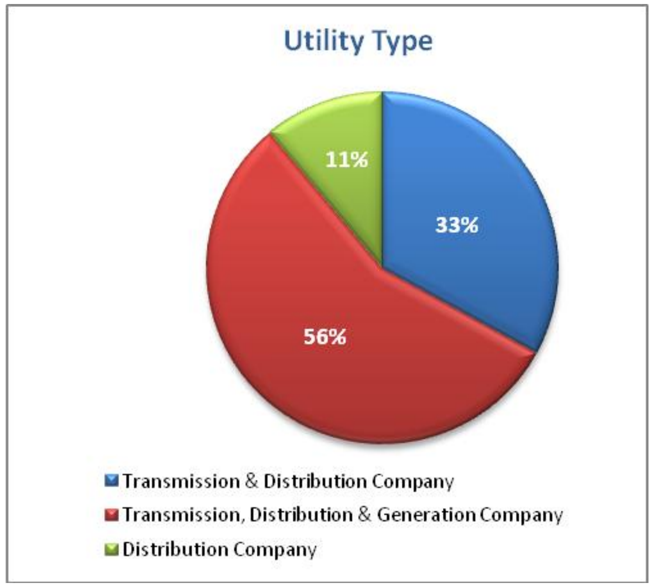


Figure 12: Utility Type

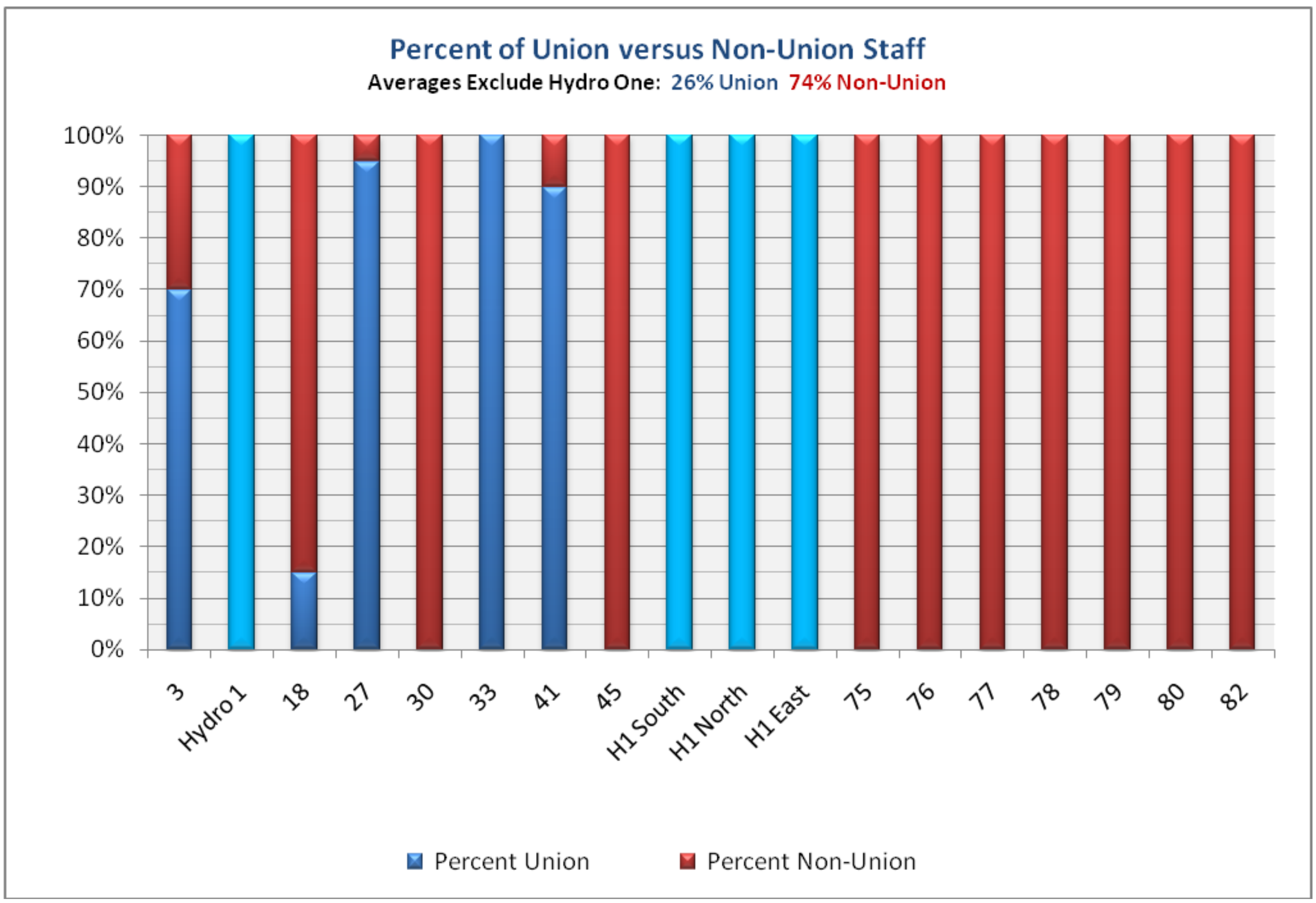


Figure 13: Percent of Union versus non-Union Staff

E.II. Efficiency and Productivity

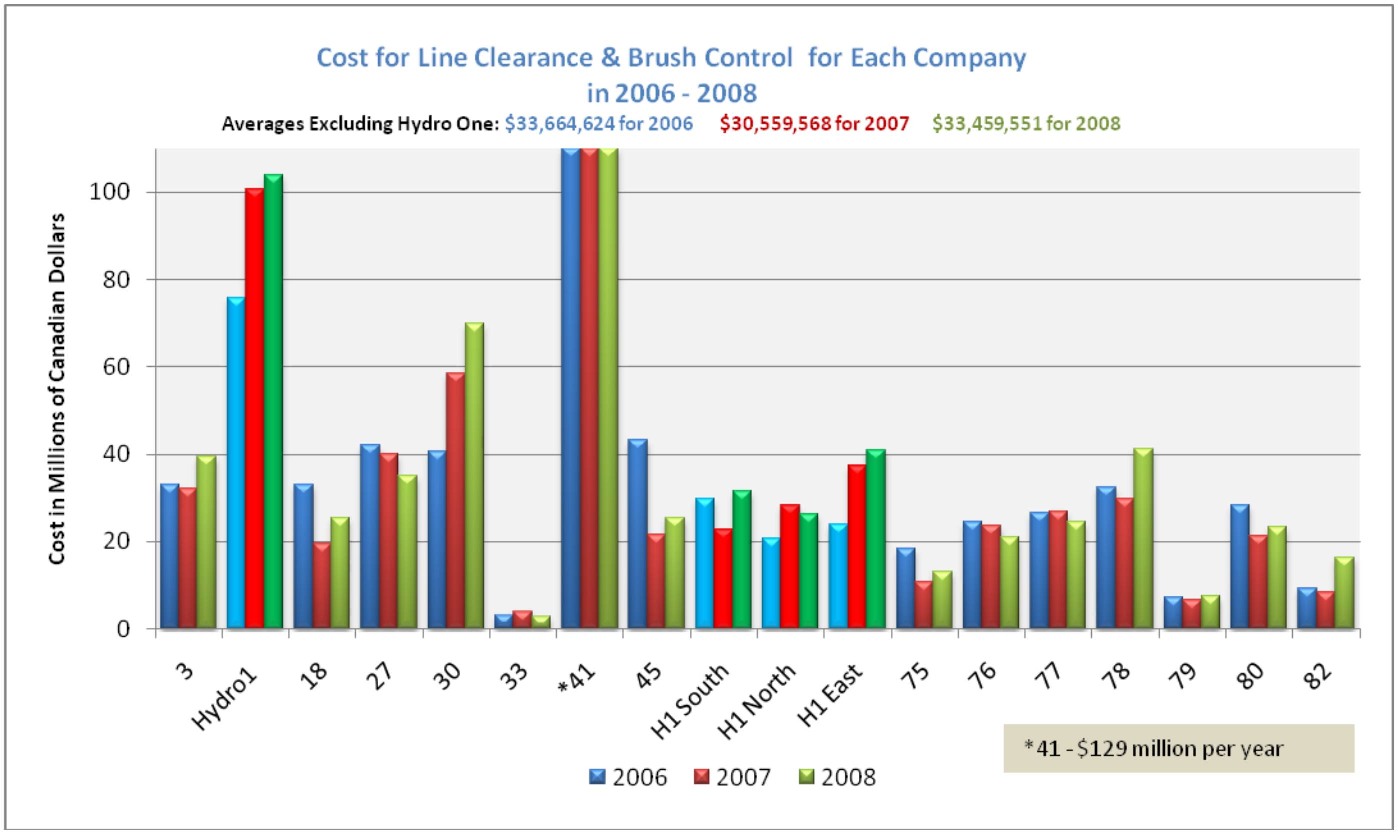


Figure 14: Cost for Line Clearance & Brush Control for Each Company

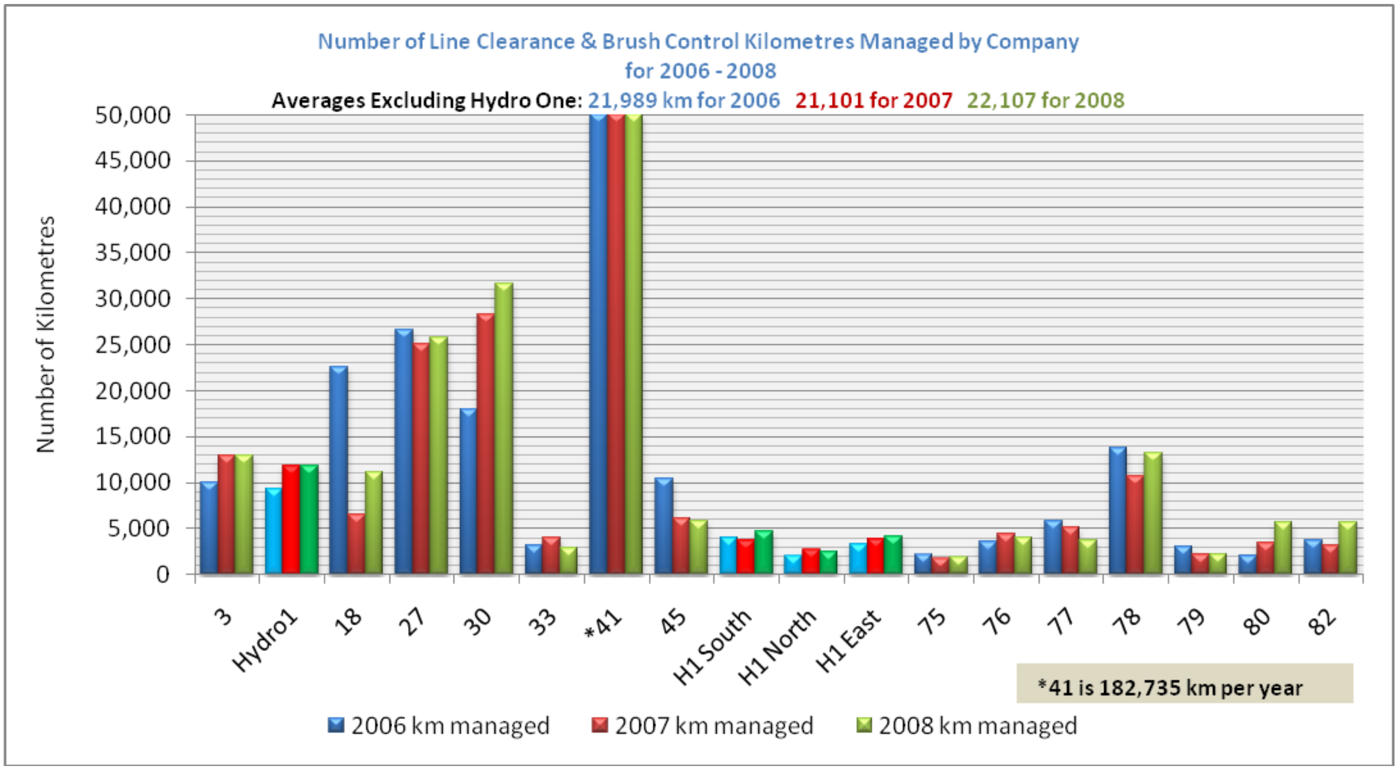


Figure 15: Number of Line Clearance & Brush Control Kilometres Managed Per Company in 2006 – 2008

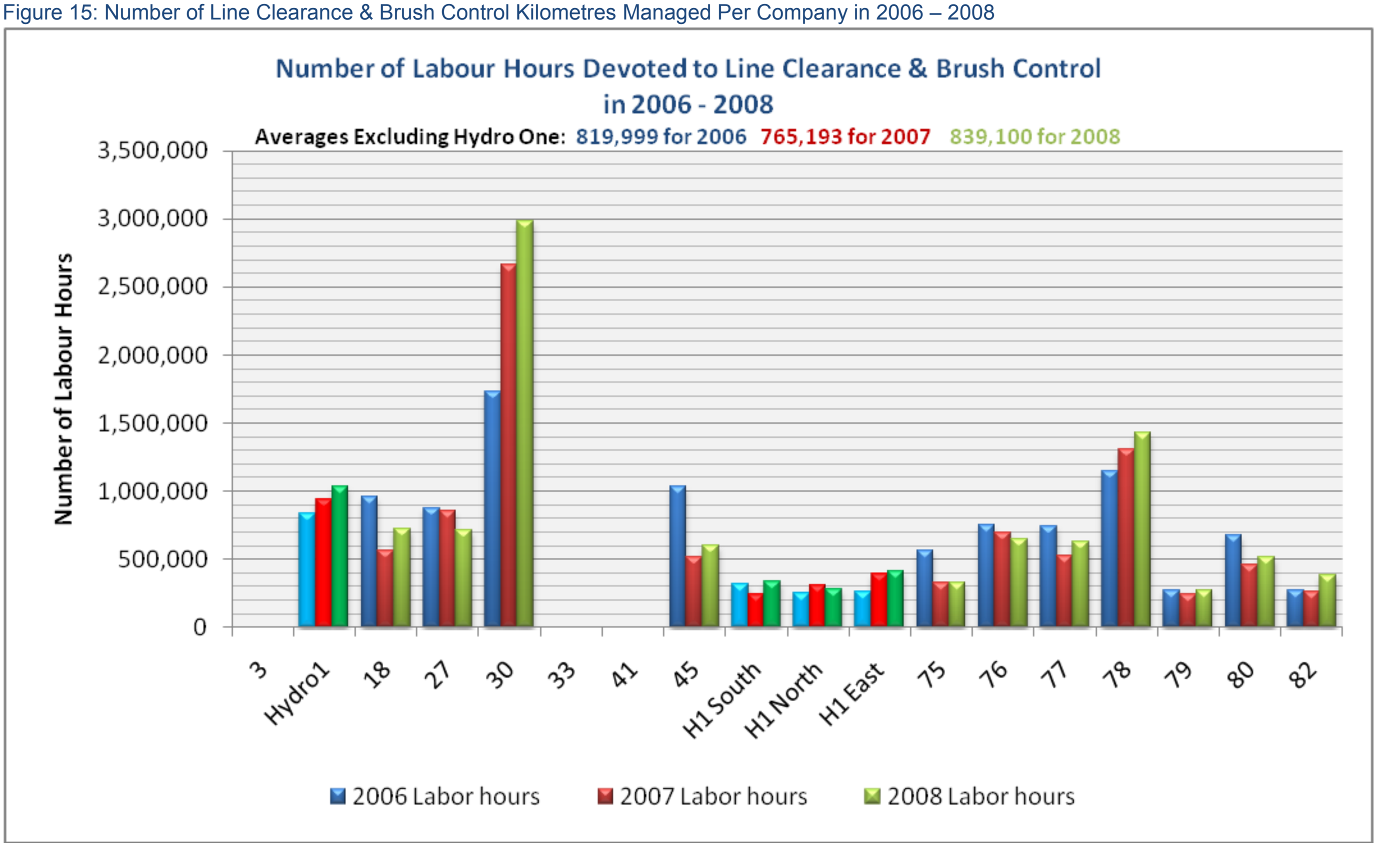


Figure 16: Number of Labour Hours Devoted to Line Clearance & Brush Control in 2006 – 2008

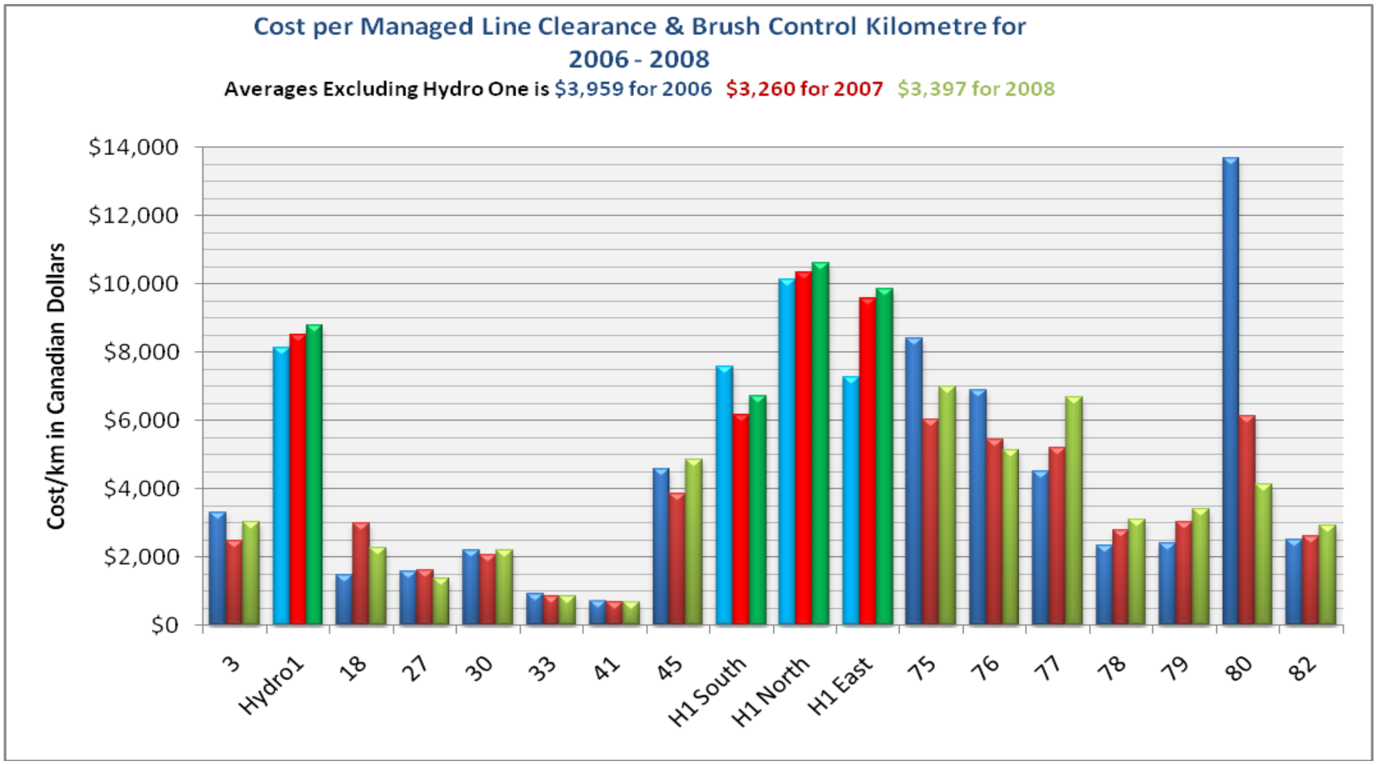


Figure 17: Cost per Managed Kilometre for Line Clearance & Brush Control in 2006 - 2008

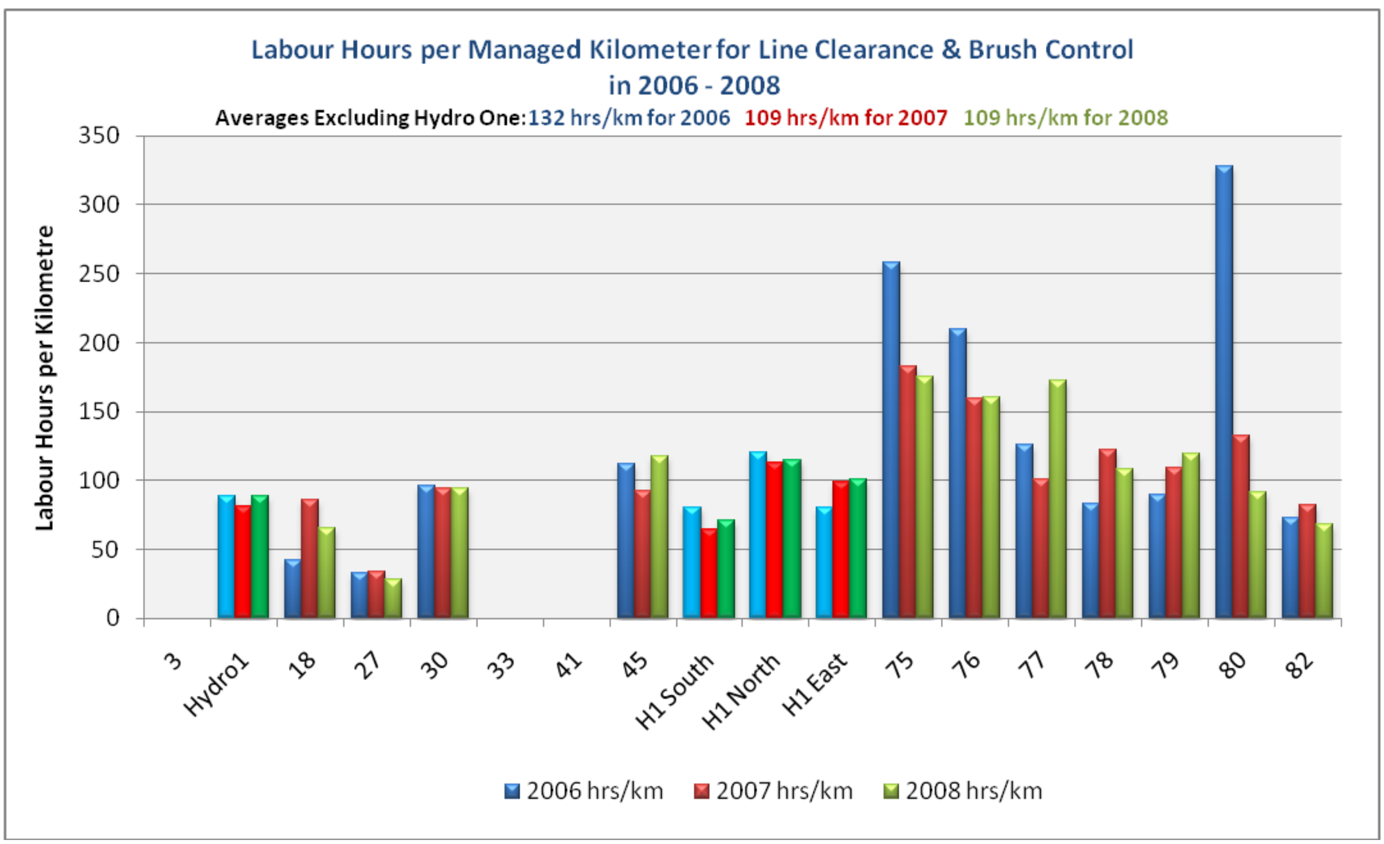


Figure 18: Labour Hours per Kilometre for Line Clearance & Brush Control in 2006 – 2008

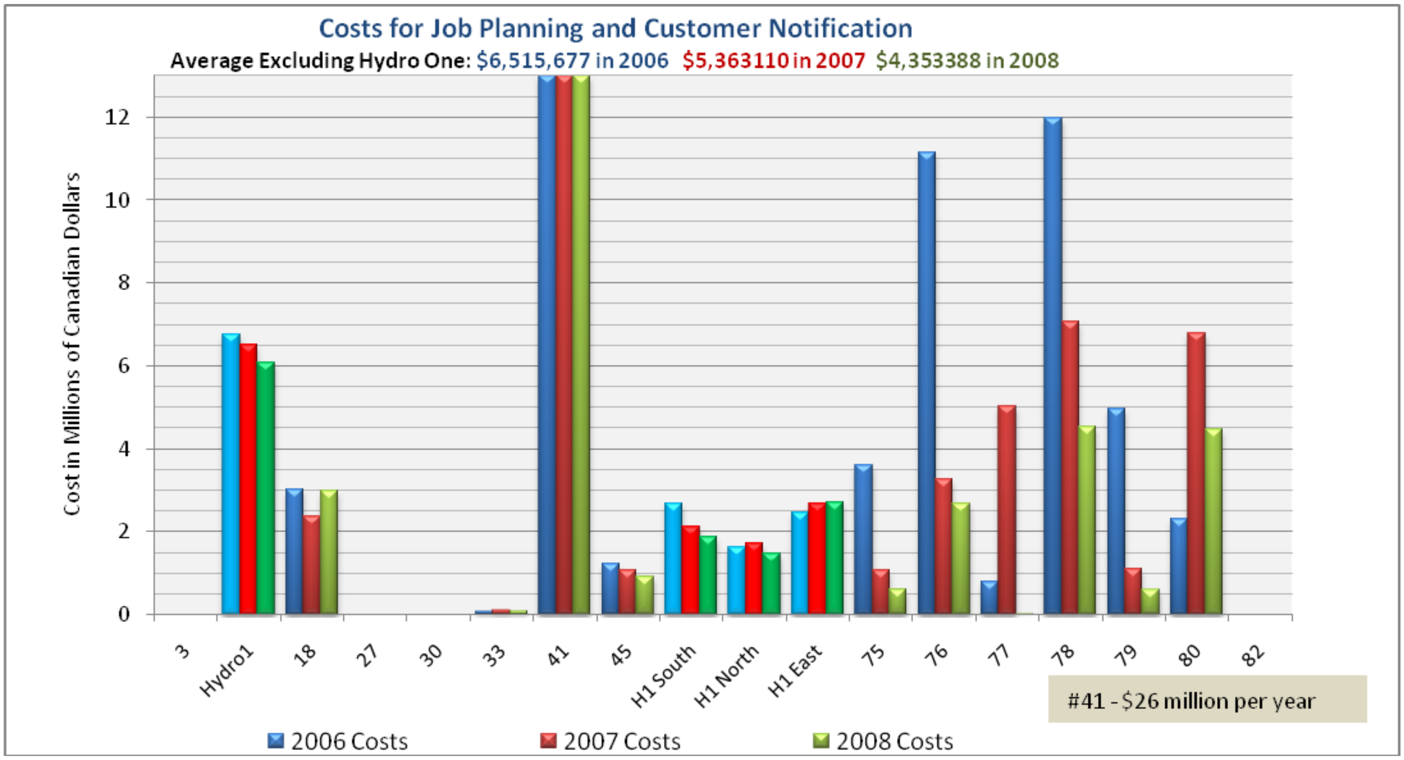


Figure 19: Cost for Job Planning and Customer Notification for 2006 – 2008

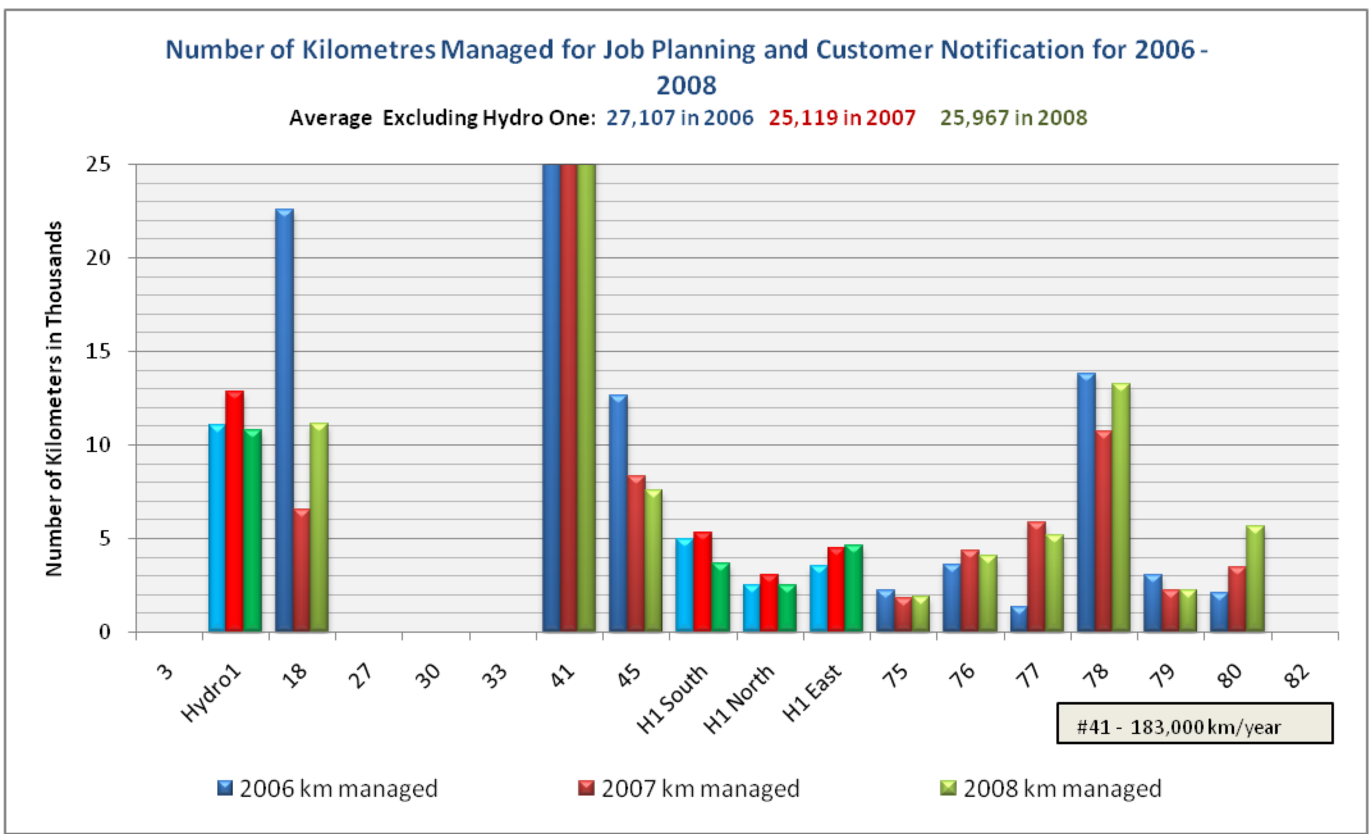


Figure 20: Number of Kilometres Managed for Job Planning and Customer Notification for 2006 – 2008

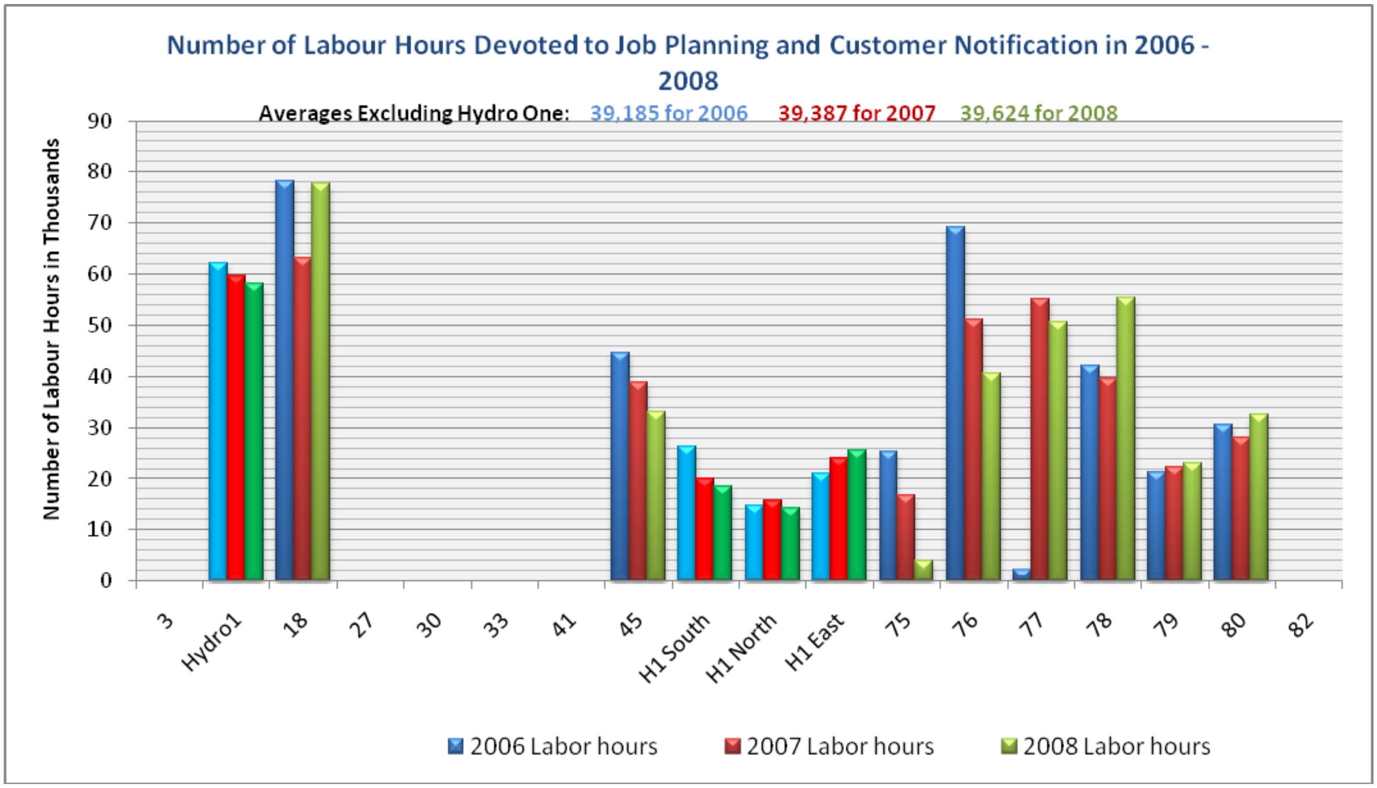


Figure 21: Number of Labour Hours Devoted to Job Planning and Customer Notification in 2006 – 2008

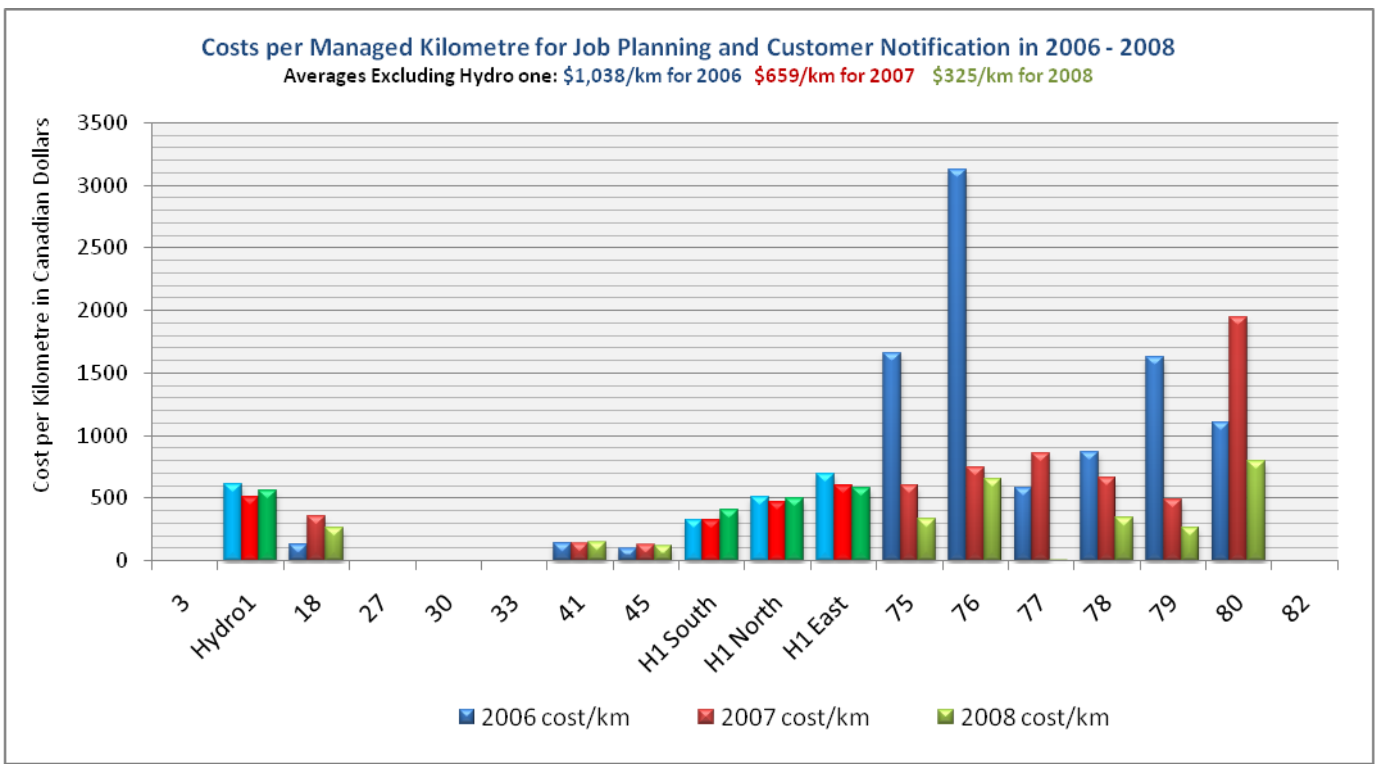


Figure 22: Cost per Managed Kilometre for Job Planning and Customer Notification in 2006 – 2008

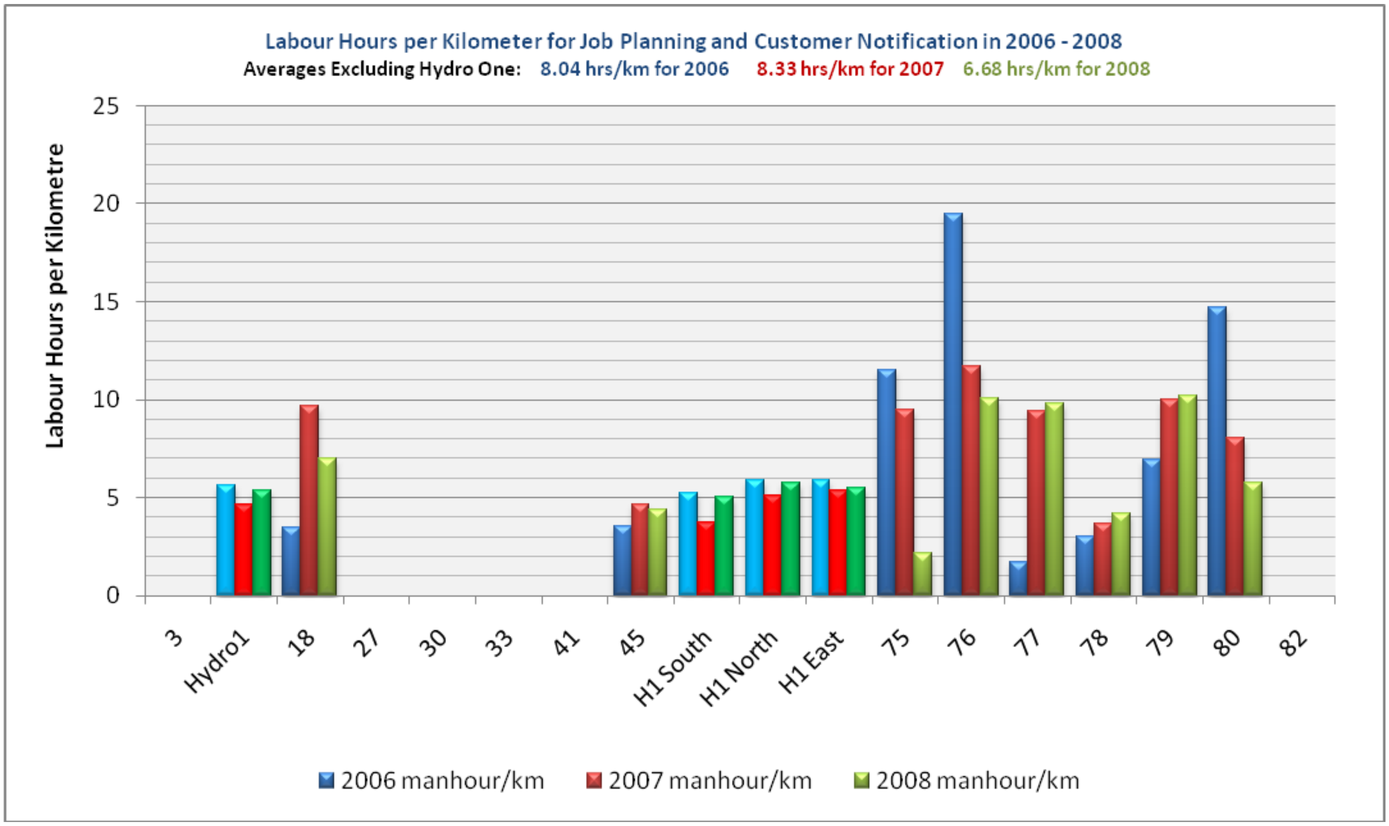


Figure 23: Labour Hours per Kilometre for Job Planning and Customer Notification in 2006 – 2008

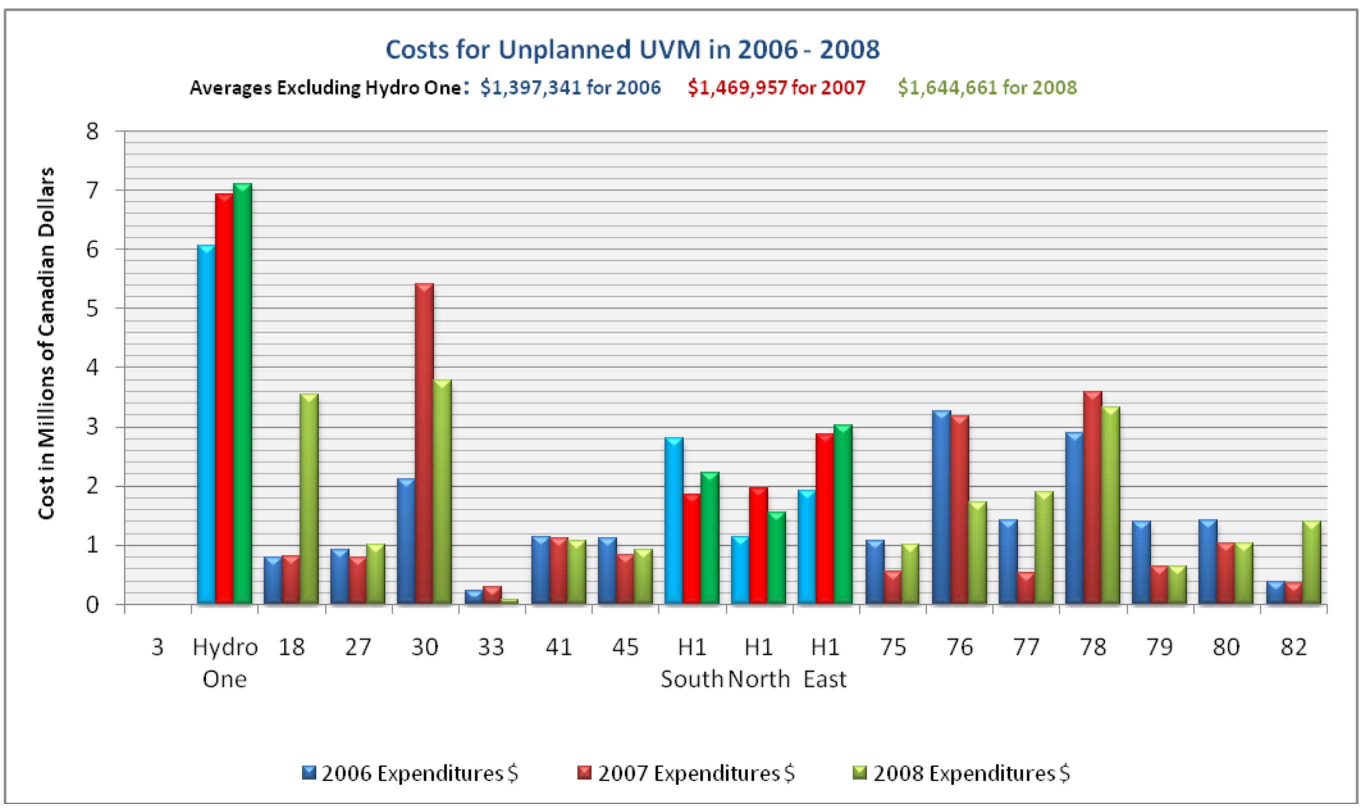


Figure 24: Cost for Unplanned UVM in 2006 – 2008

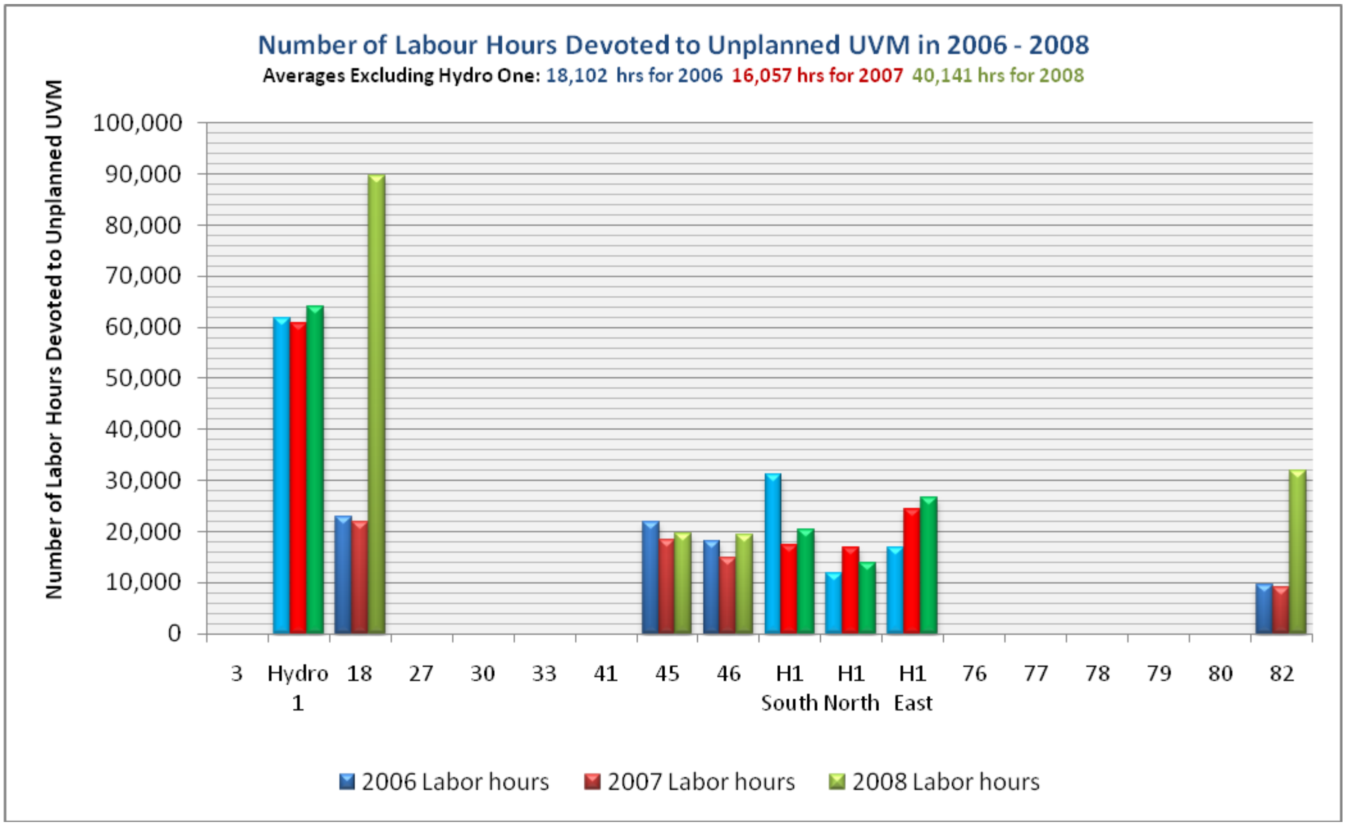


Figure 25: Number of Labour Hours Devoted to Unplanned UVM in 2006 – 2008

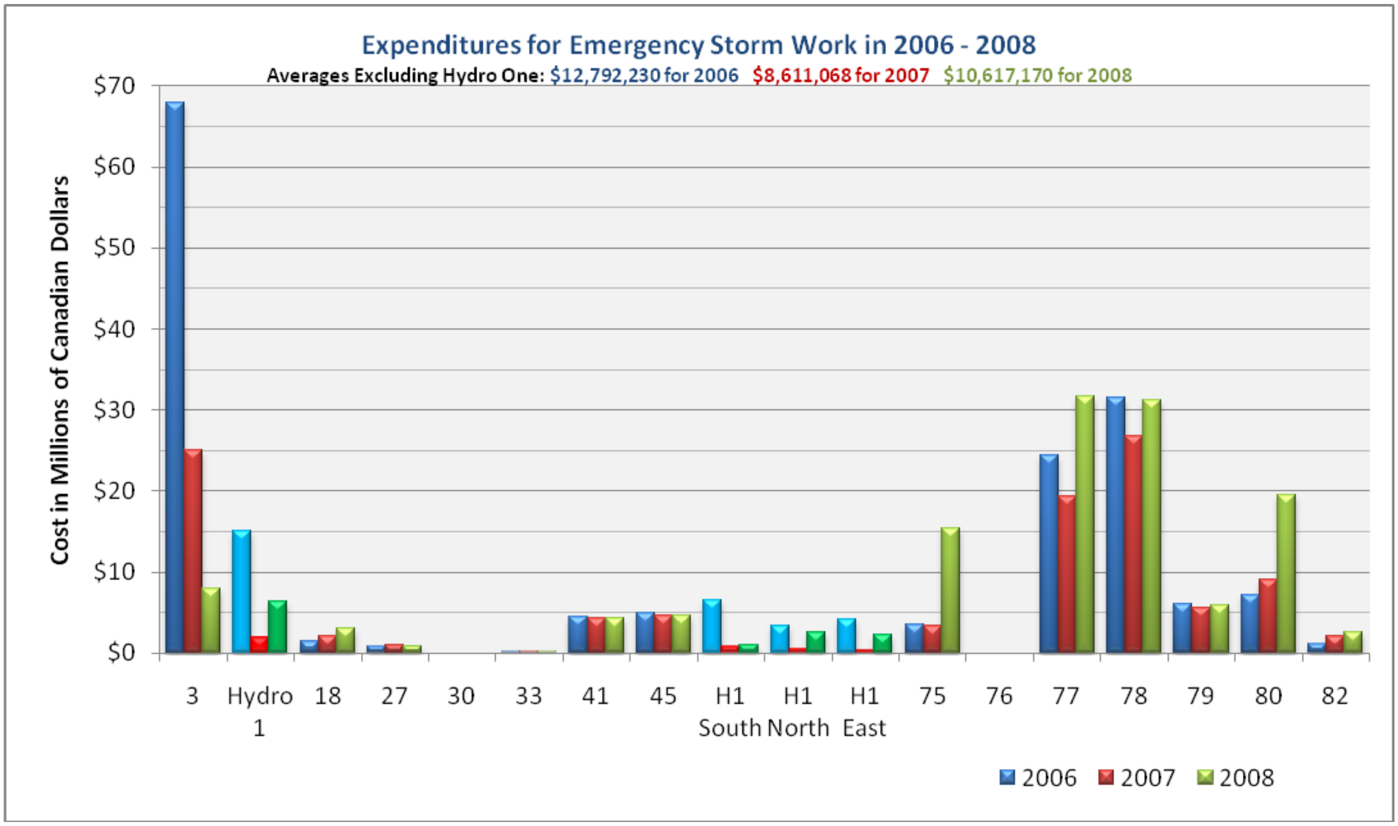


Figure 26: Cost for Emergency Storm Work 2006 – 2008

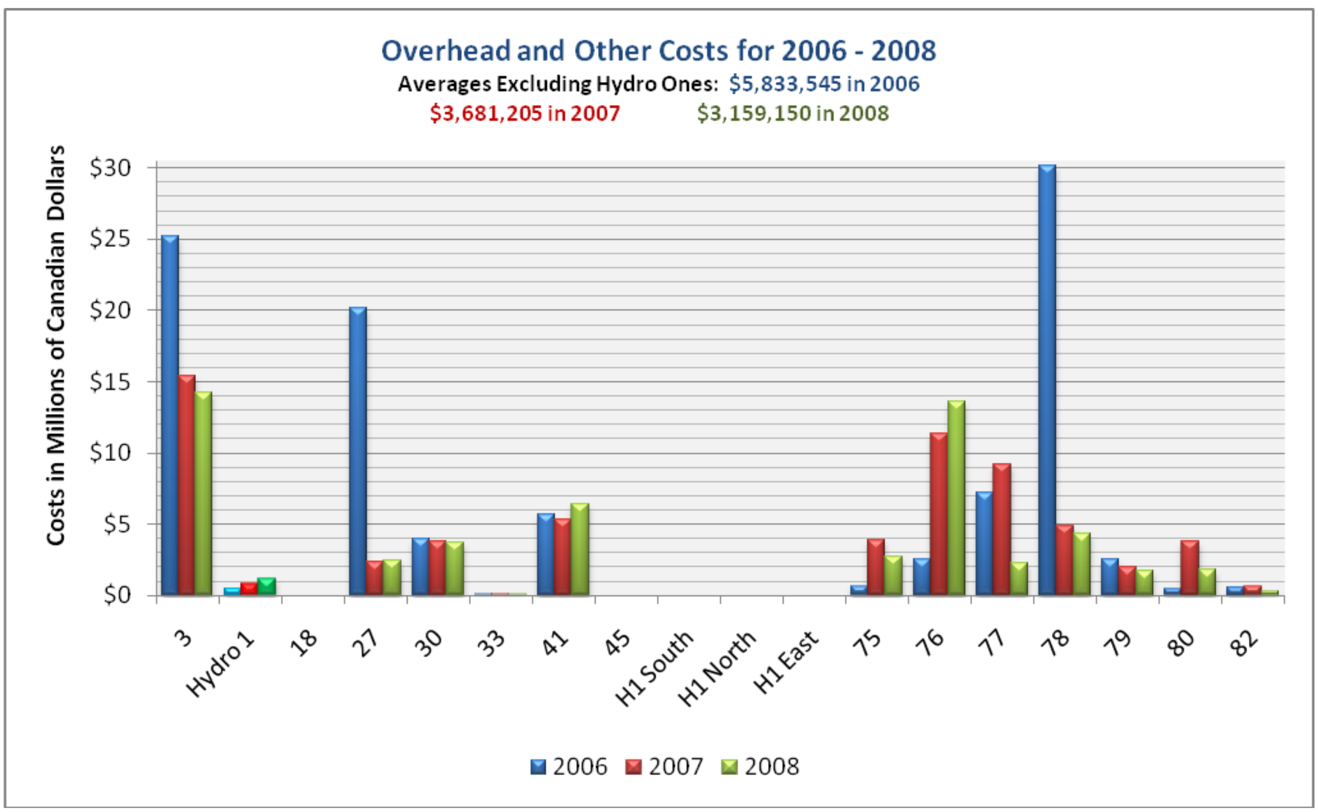


Figure 27: Overhead and Other Costs for 2006 - 2008

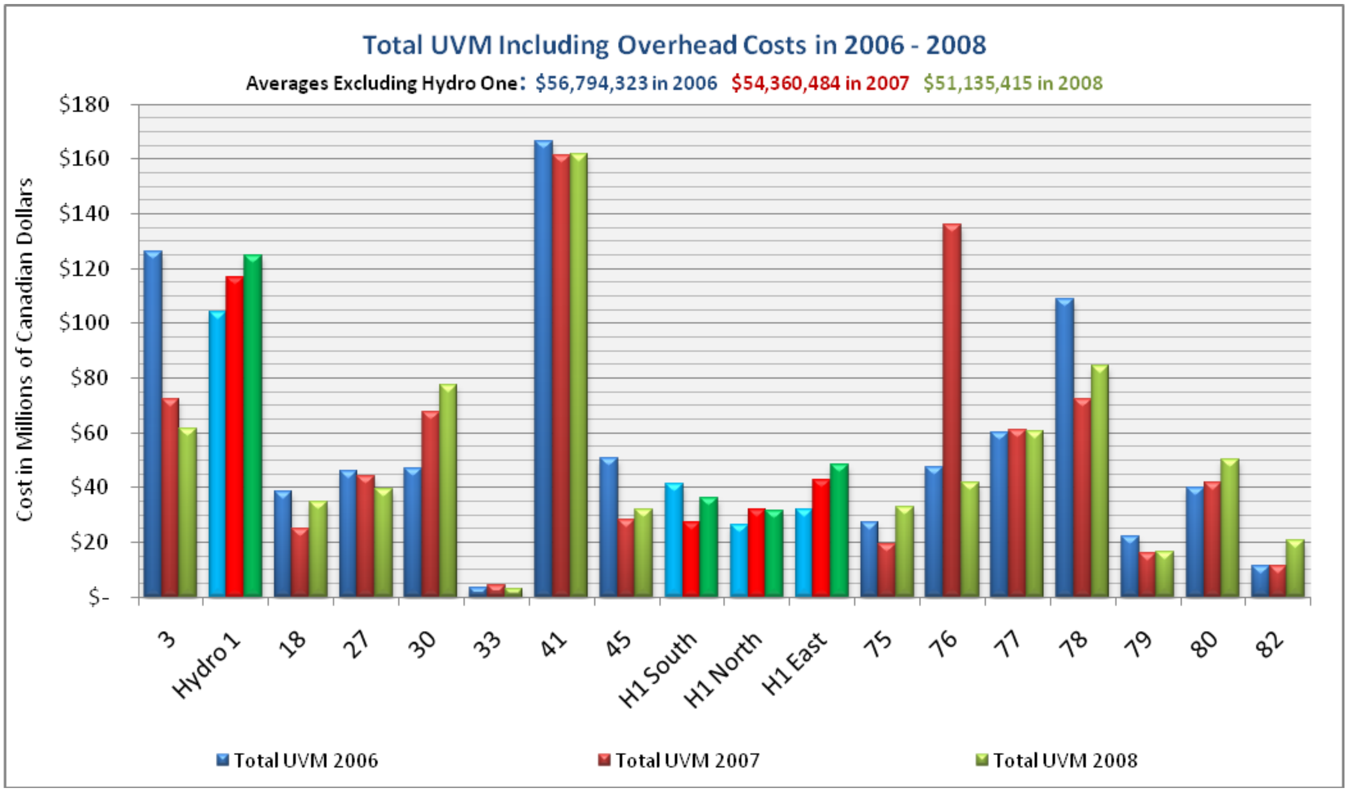


Figure 28: Total UVM Including Overhead Costs in 2006 – 2008

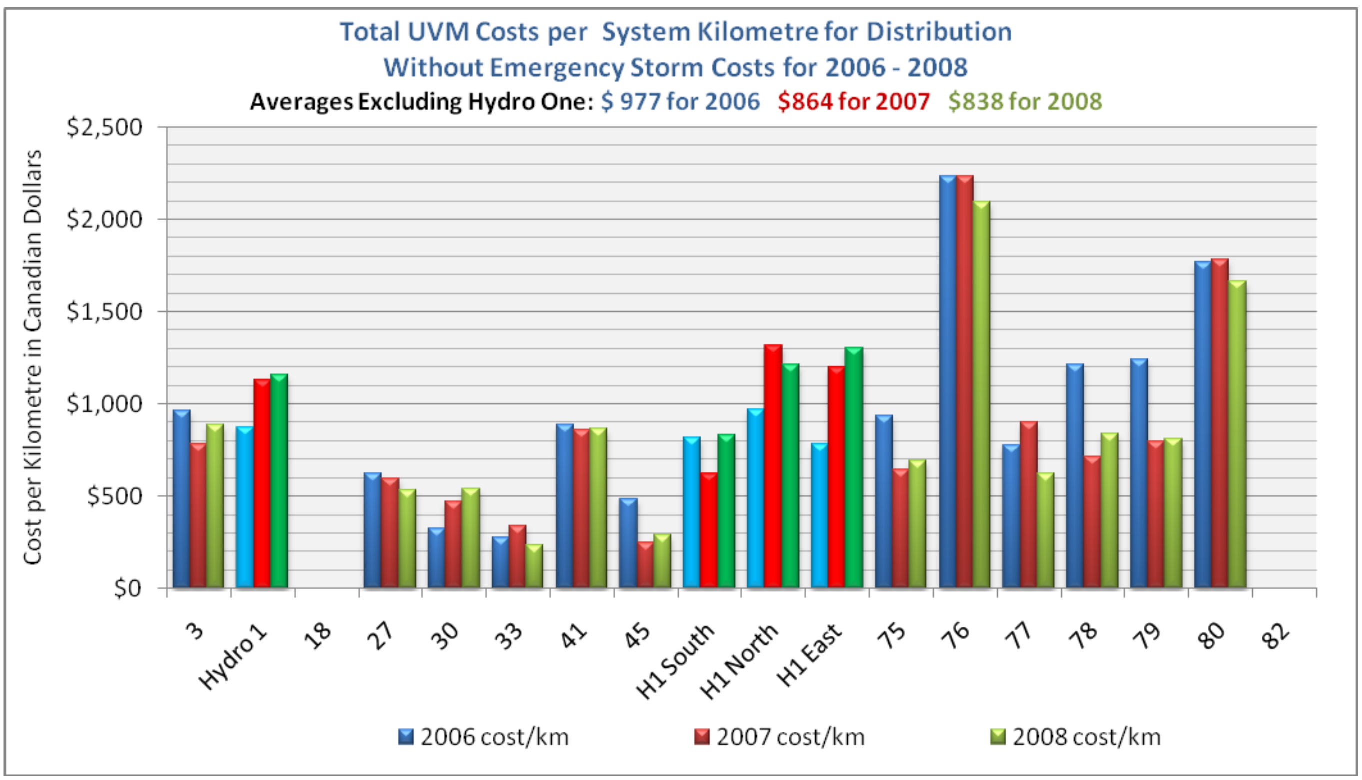


Figure 29: Total UVM Costs per Kilometre Without Emergency Storm Costs in 2006 - 2008

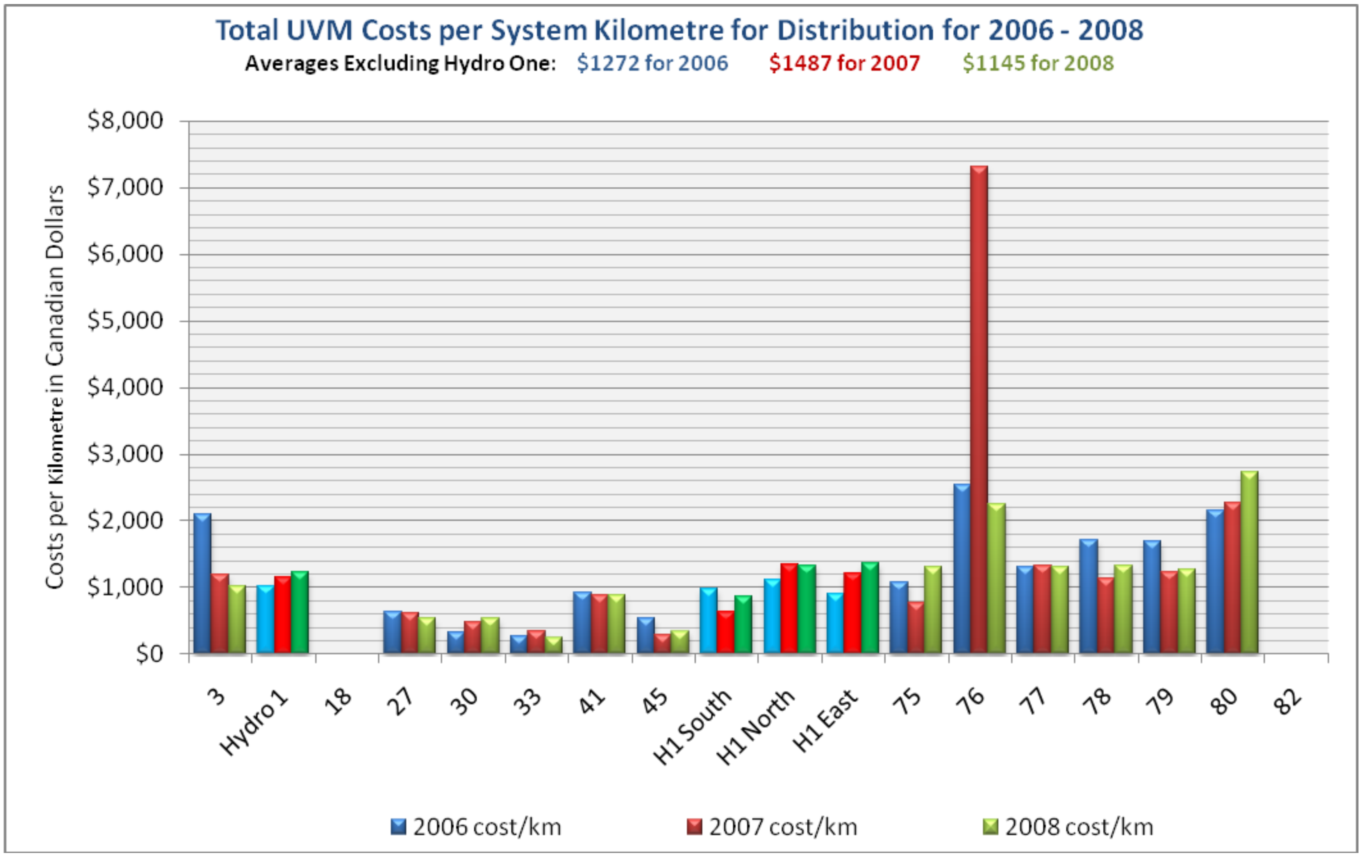


Figure 30: Total UVM Costs per Kilometre With Emergency Storm Costs 2006 - 2008

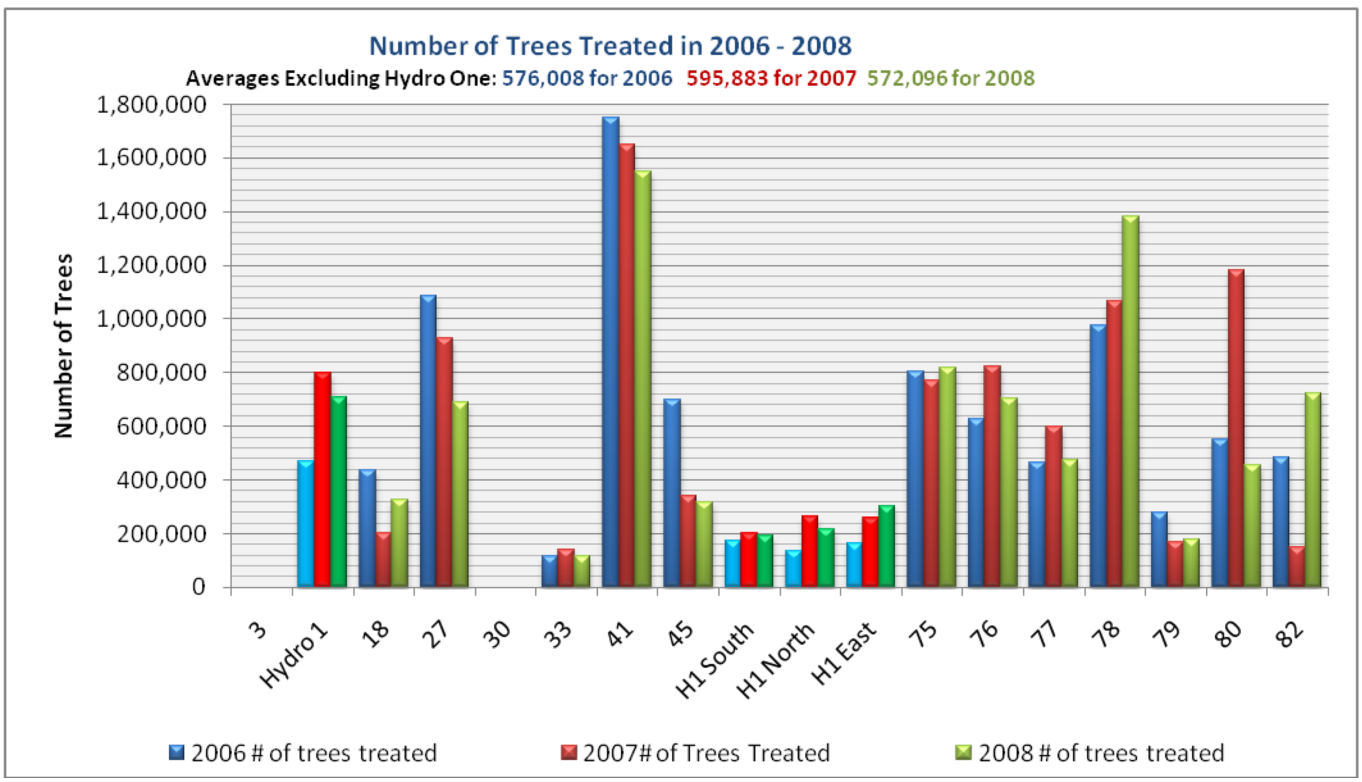


Figure 31: Number of Trees Treated in 2006 – 2008

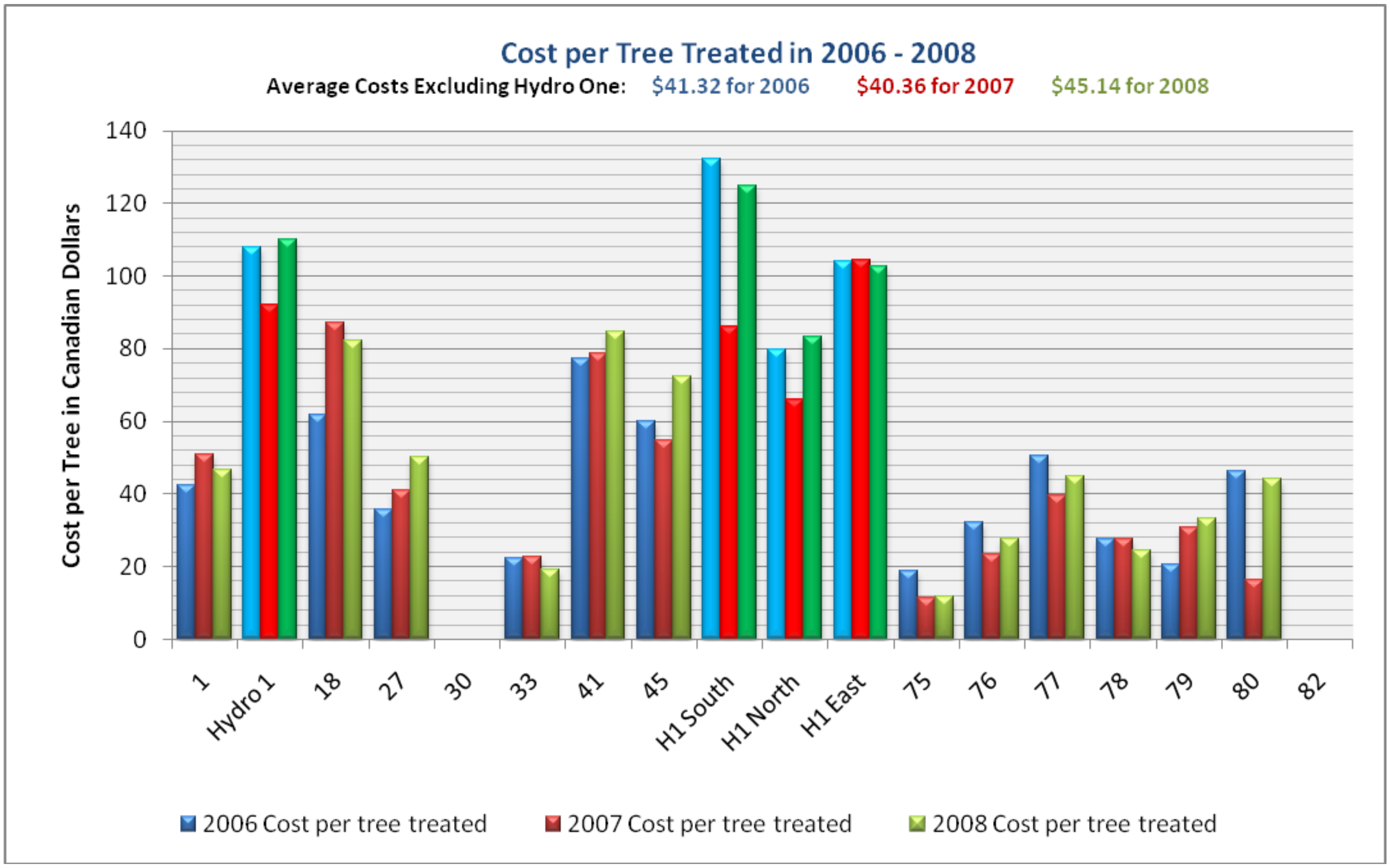


Figure 32: Cost per Tree Treated in 2006 - 2008

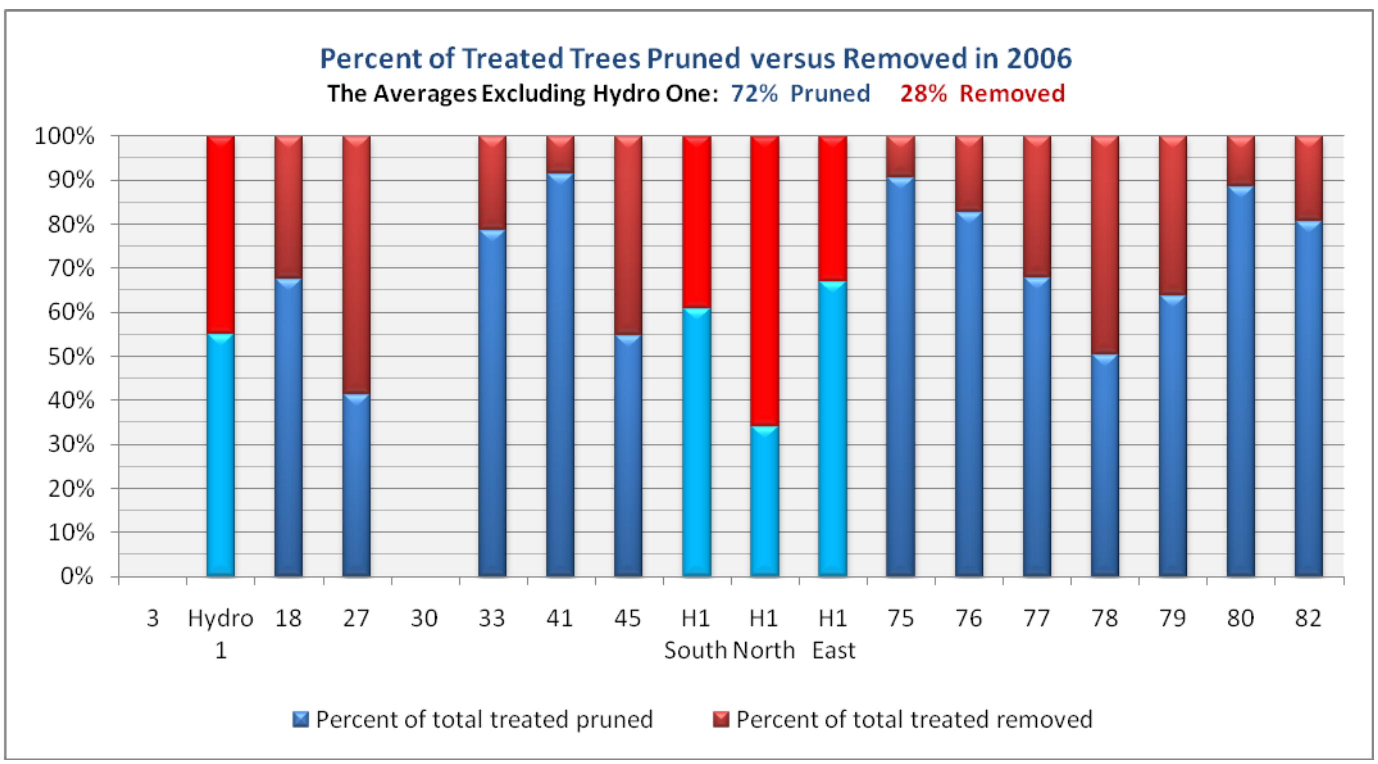


Figure 33: Percent of Pruned Trees versus Removed for 2006

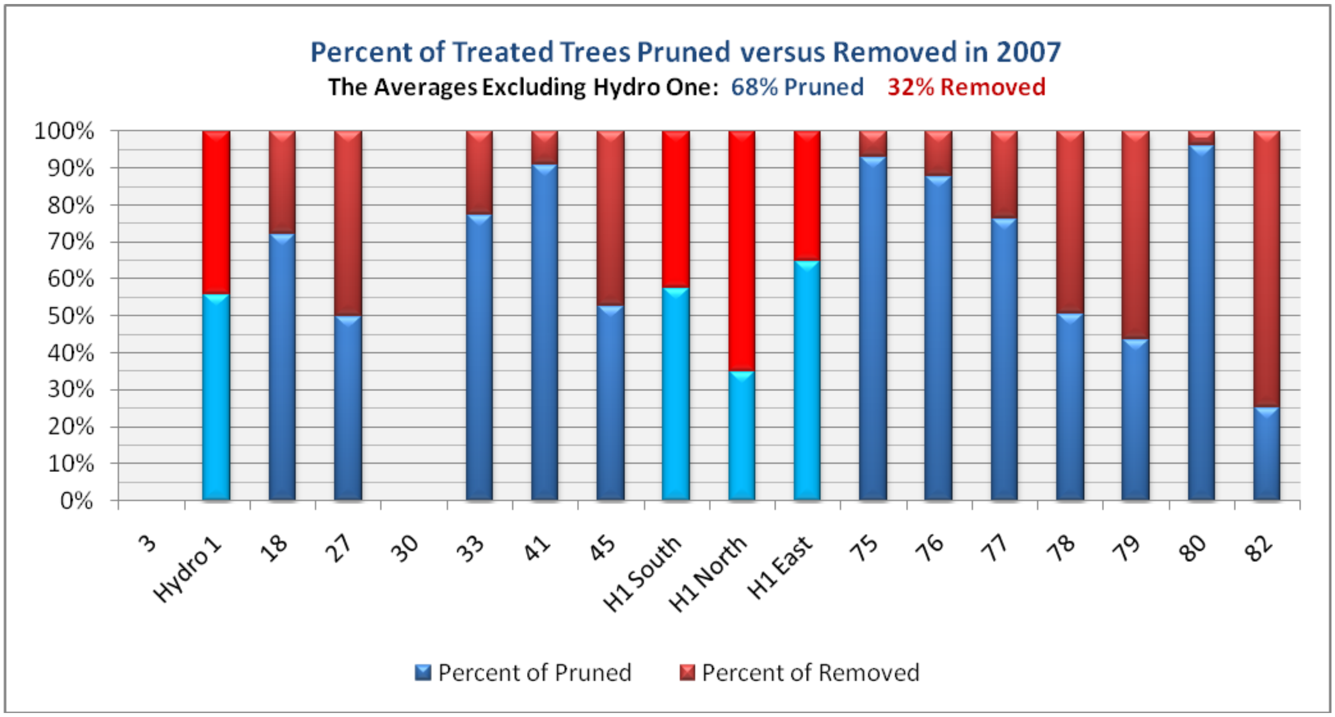


Figure 34: Percent of Trees Pruned versus Removed for 2007

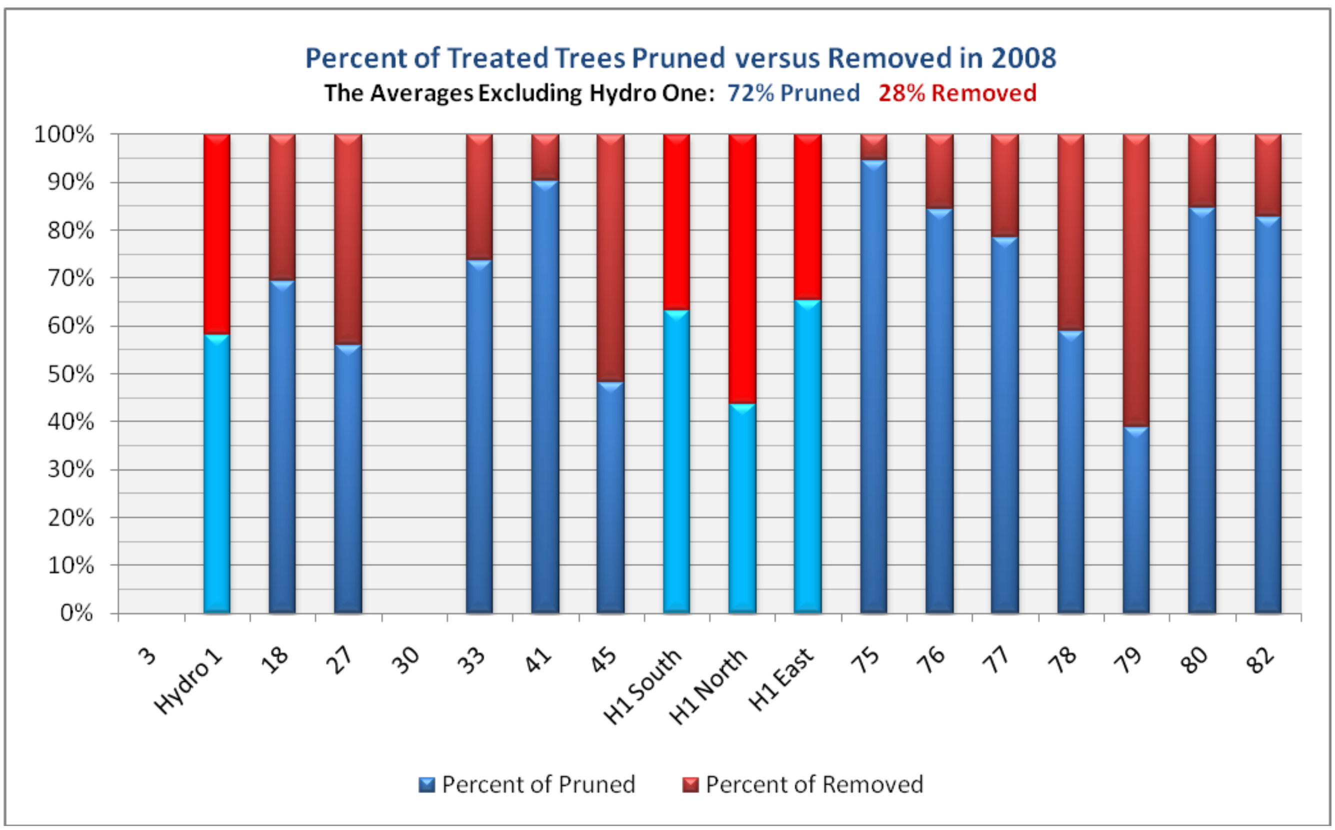


Figure 35: Percent of Trees Pruned versus Removed for 2008

E.III. Operational Attributes

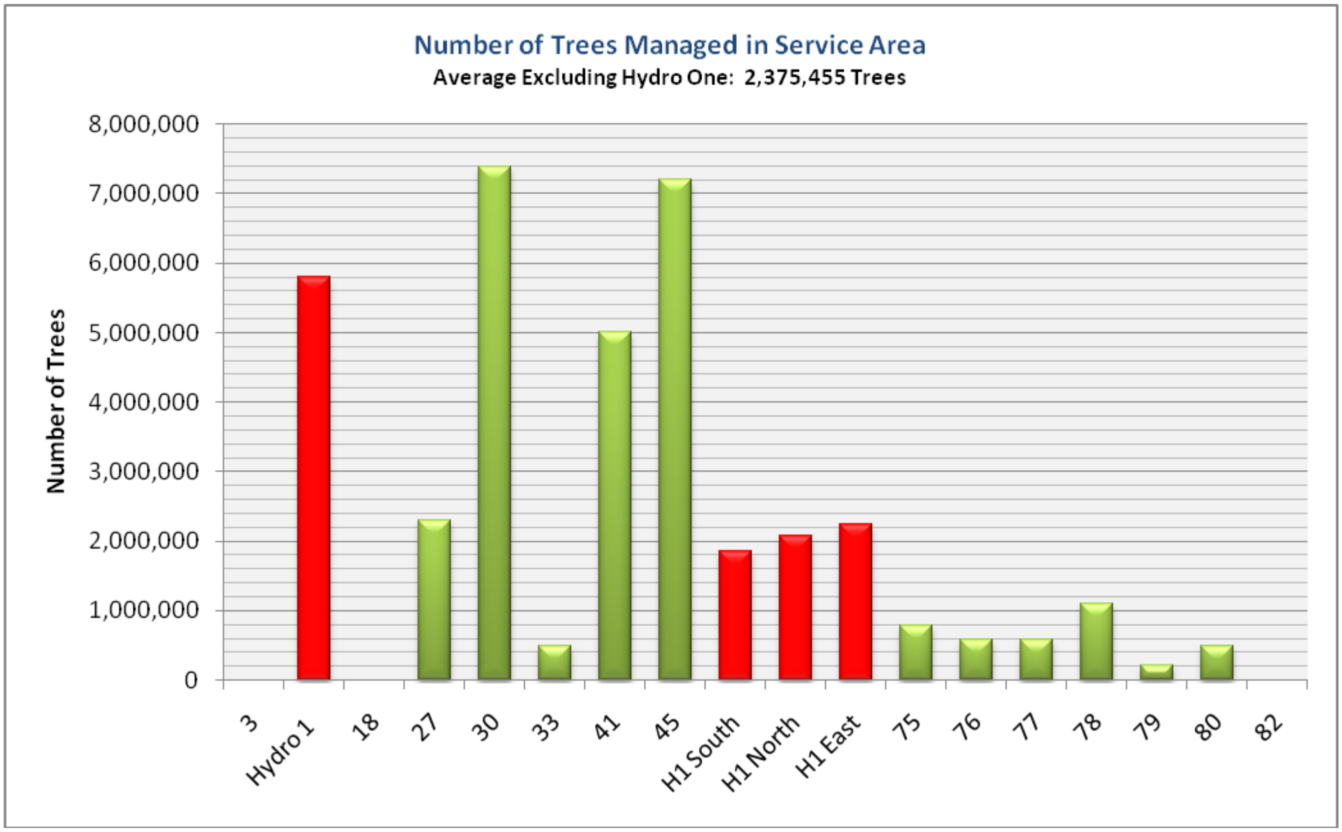


Figure 36: Number of Trees Managed in Service Territory

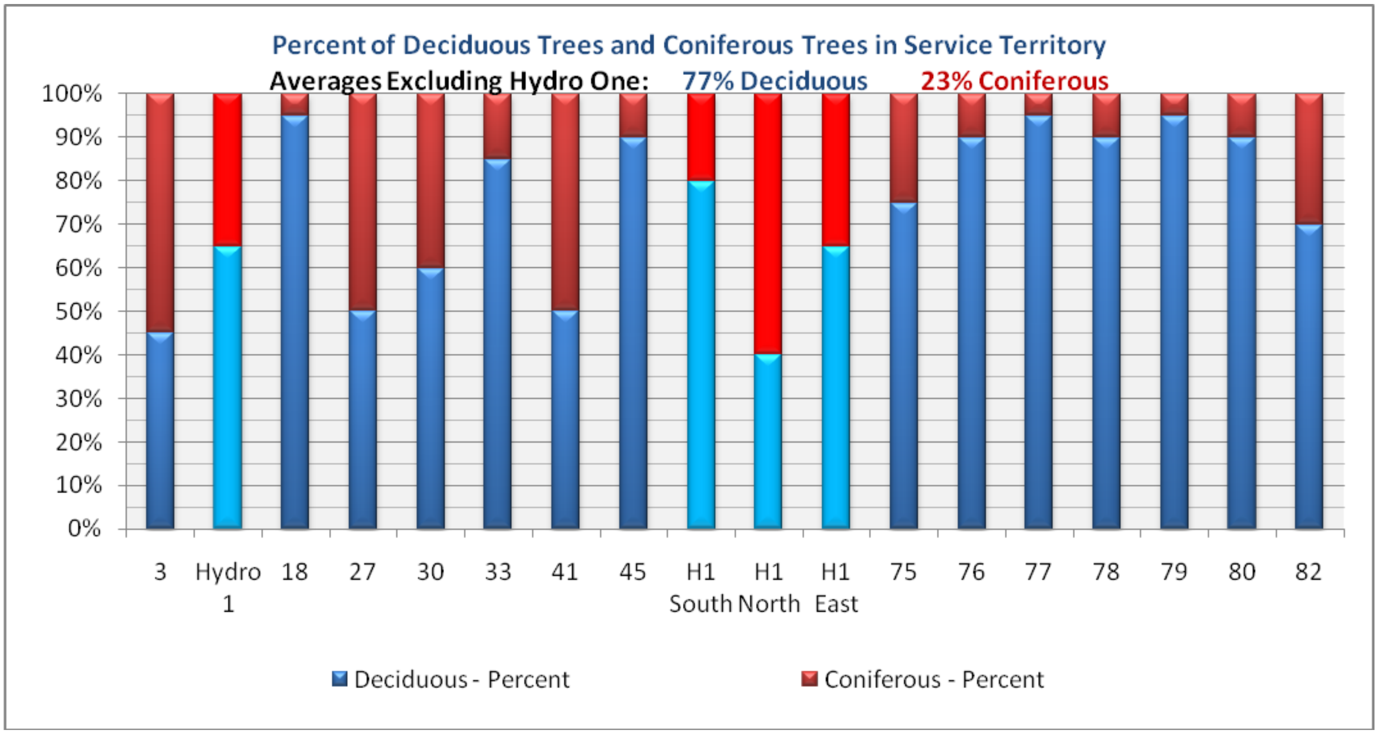


Figure 37: Percent of Deciduous Trees and Coniferous Trees in Service Territory

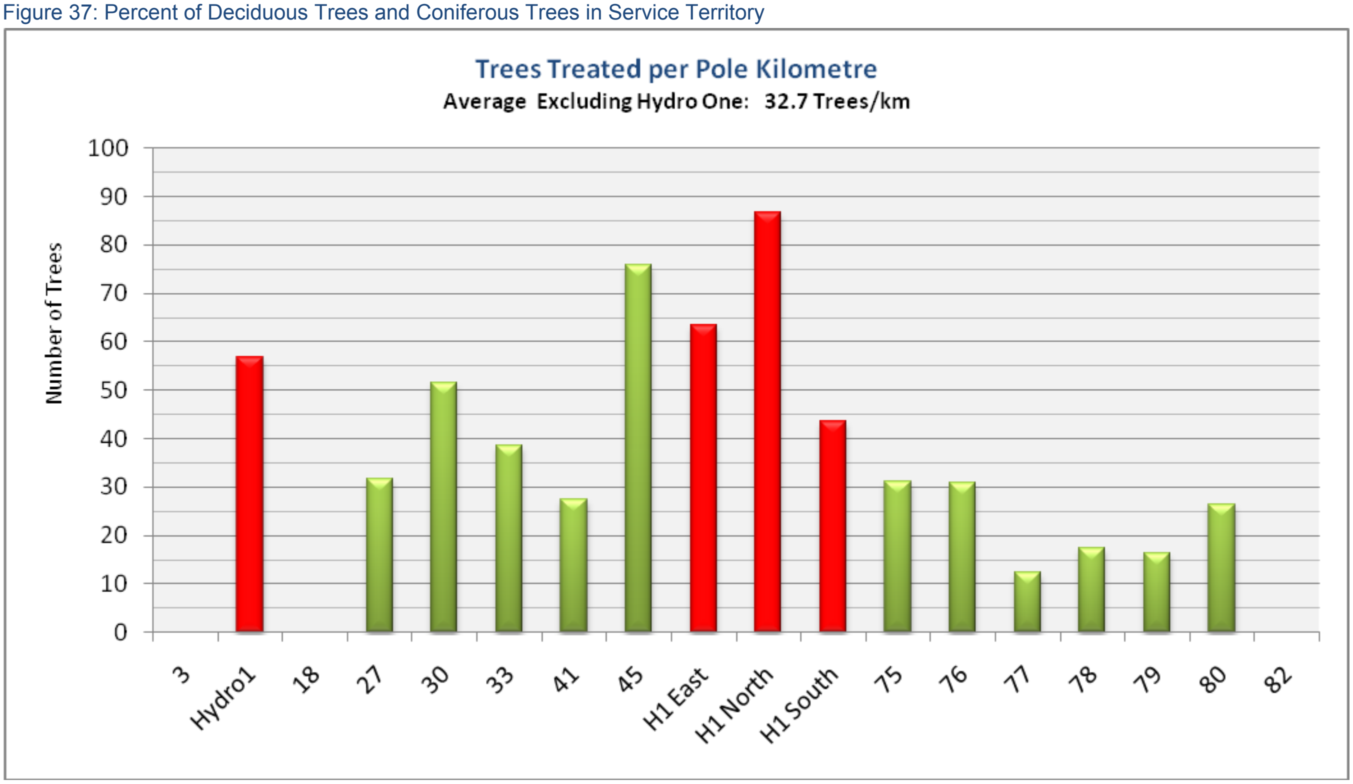


Figure 38: Trees treated Per Pole Kilometre

E.IV. Safety

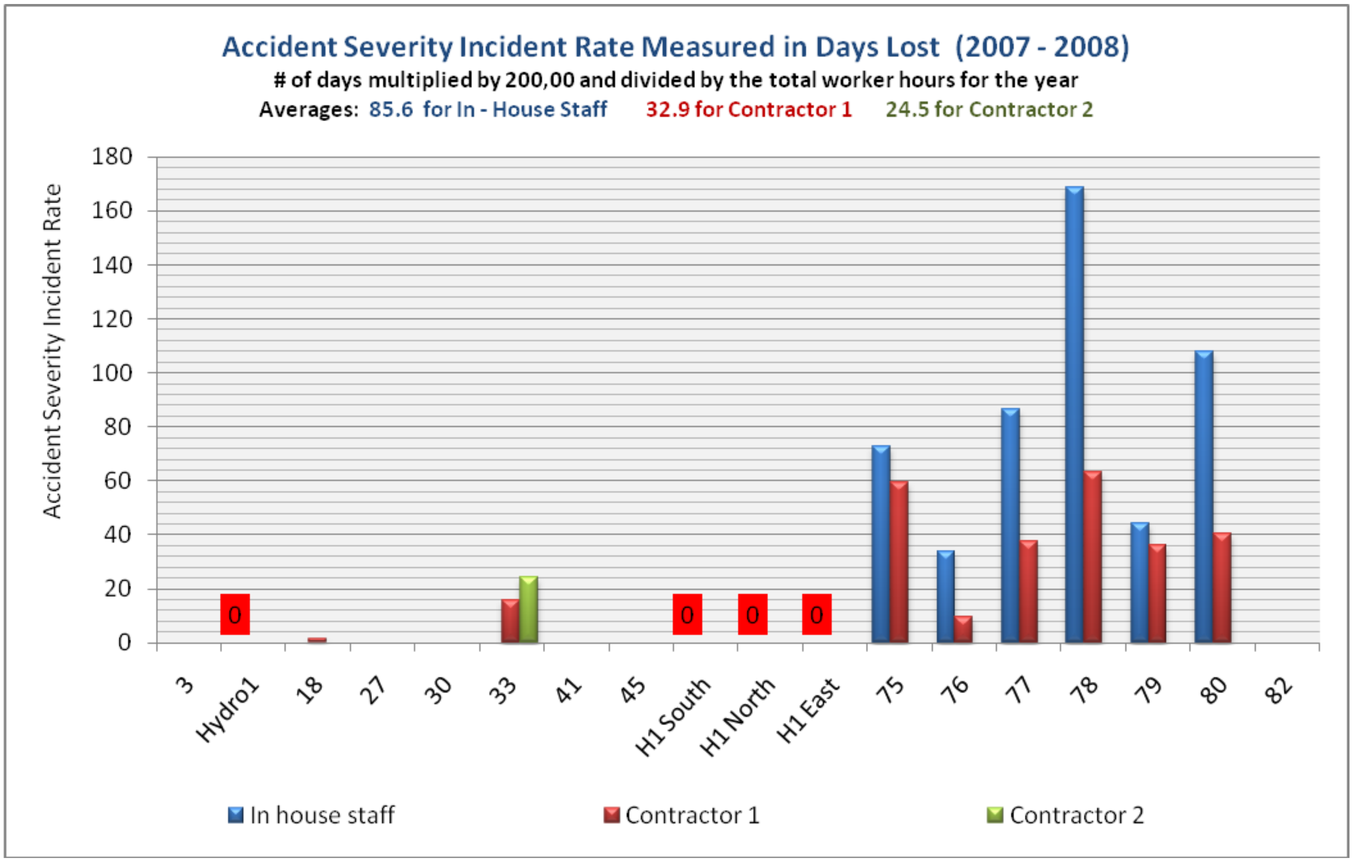


Figure 39: Accident Severity Rate for 2007- 2008

E.V. Reliability

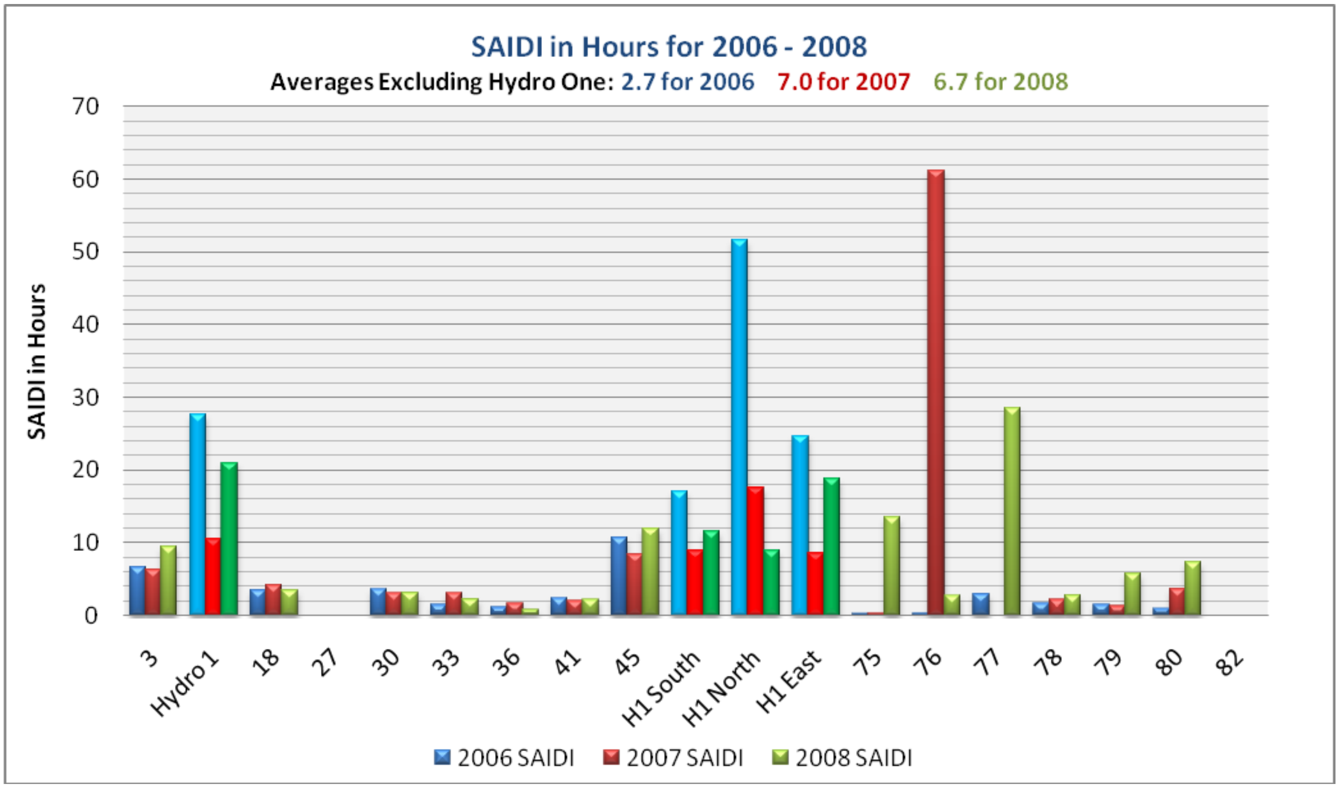


Figure 40: SAIDI in Hours for 2006 – 2008

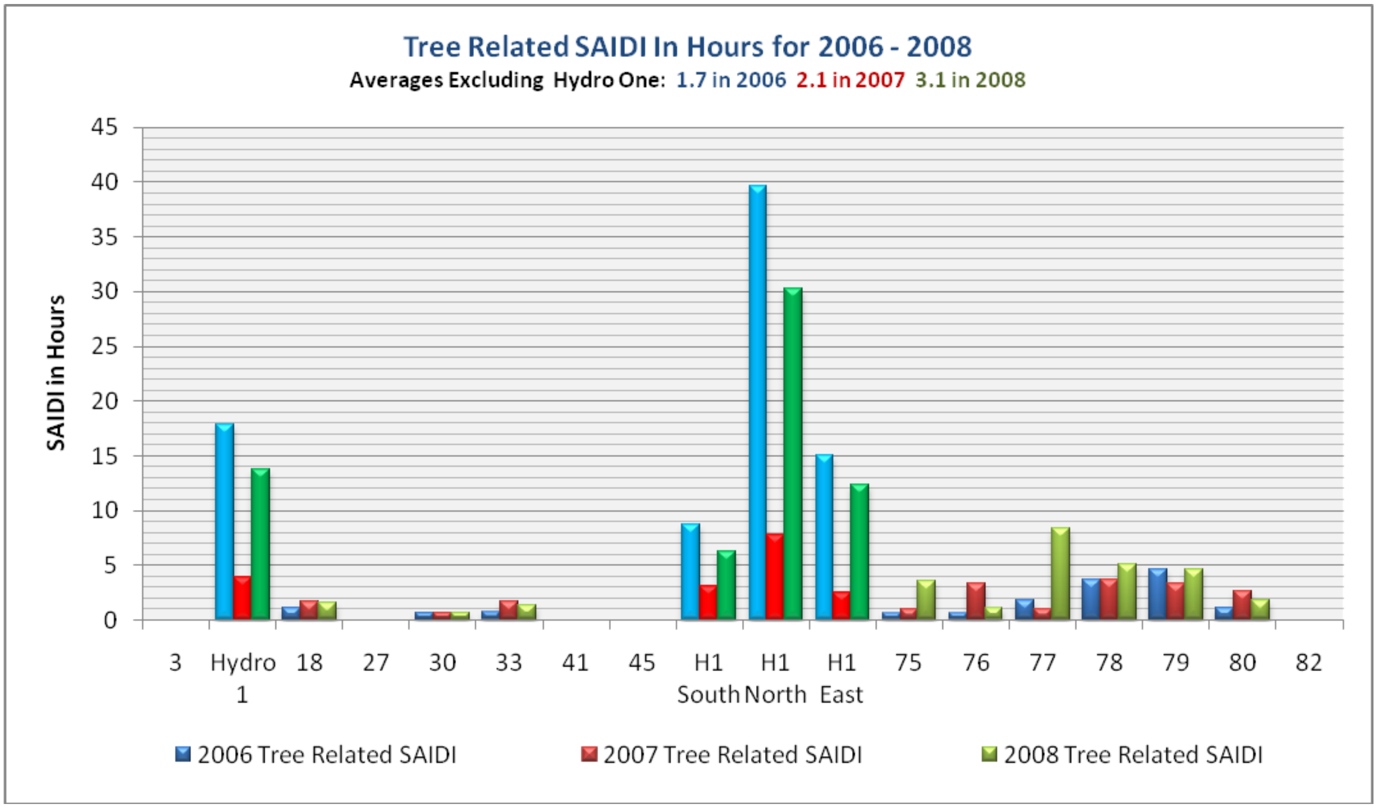


Figure 41: Tree Related SAIDI in Hours for 2006 - 2008

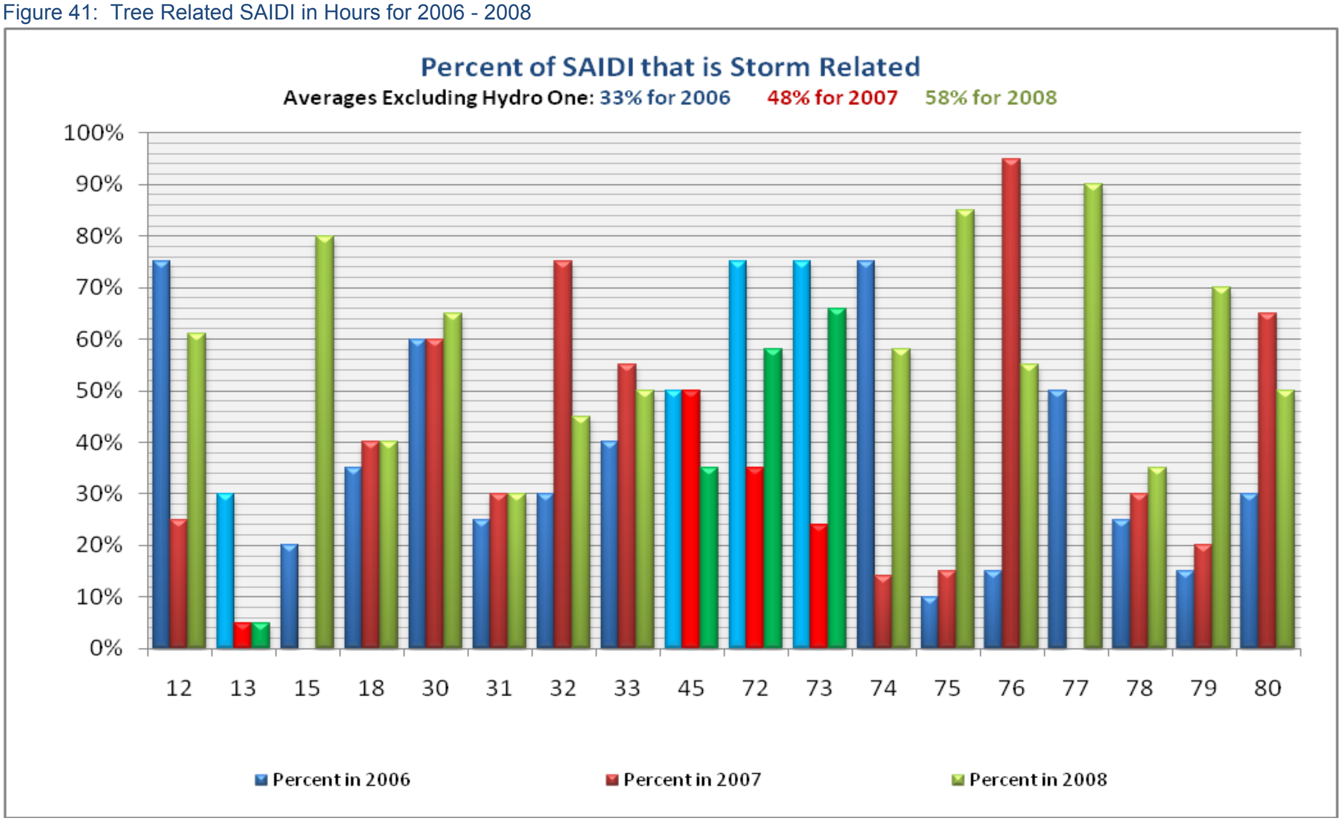


Figure 42: Percent of SAIDI that is Storm Related

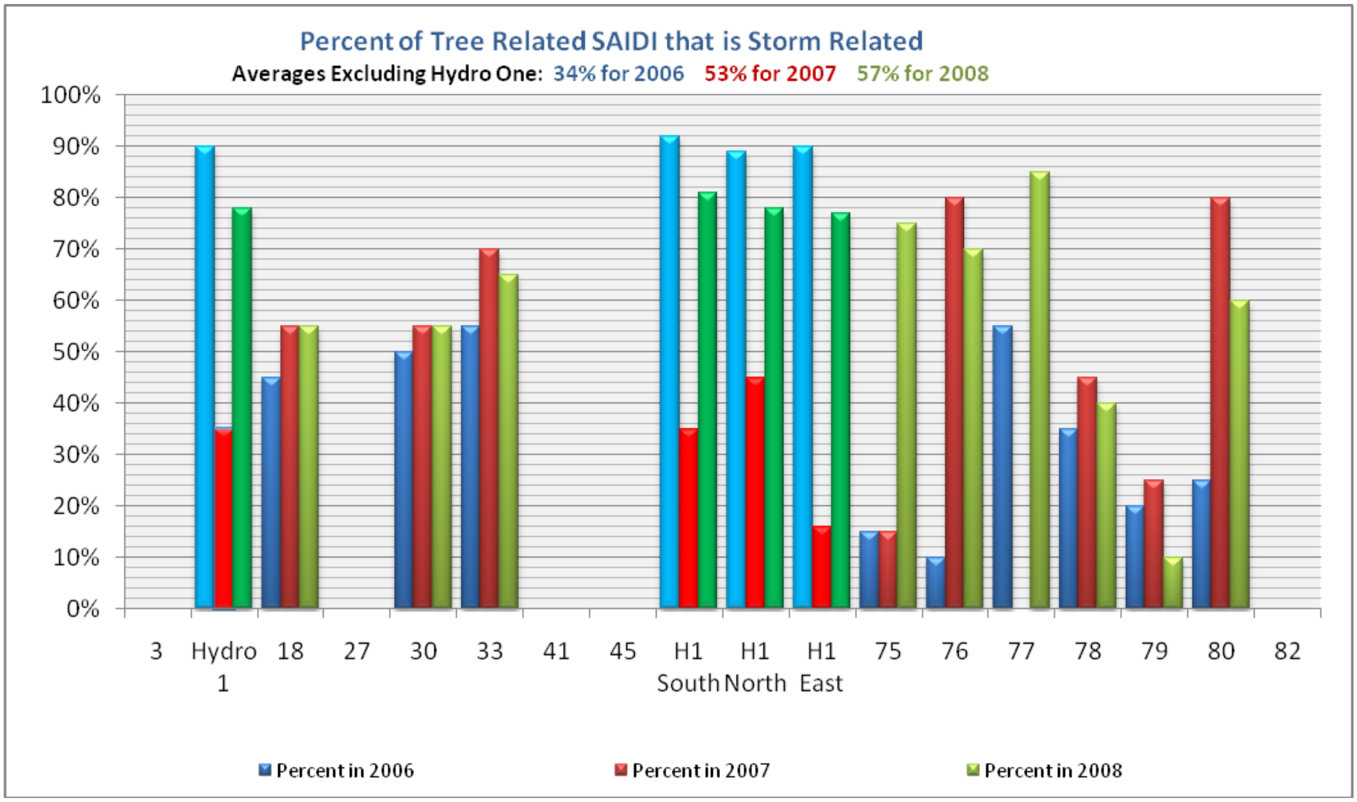


Figure 43: Percent of Tree Related SAIDI that is Storm Related

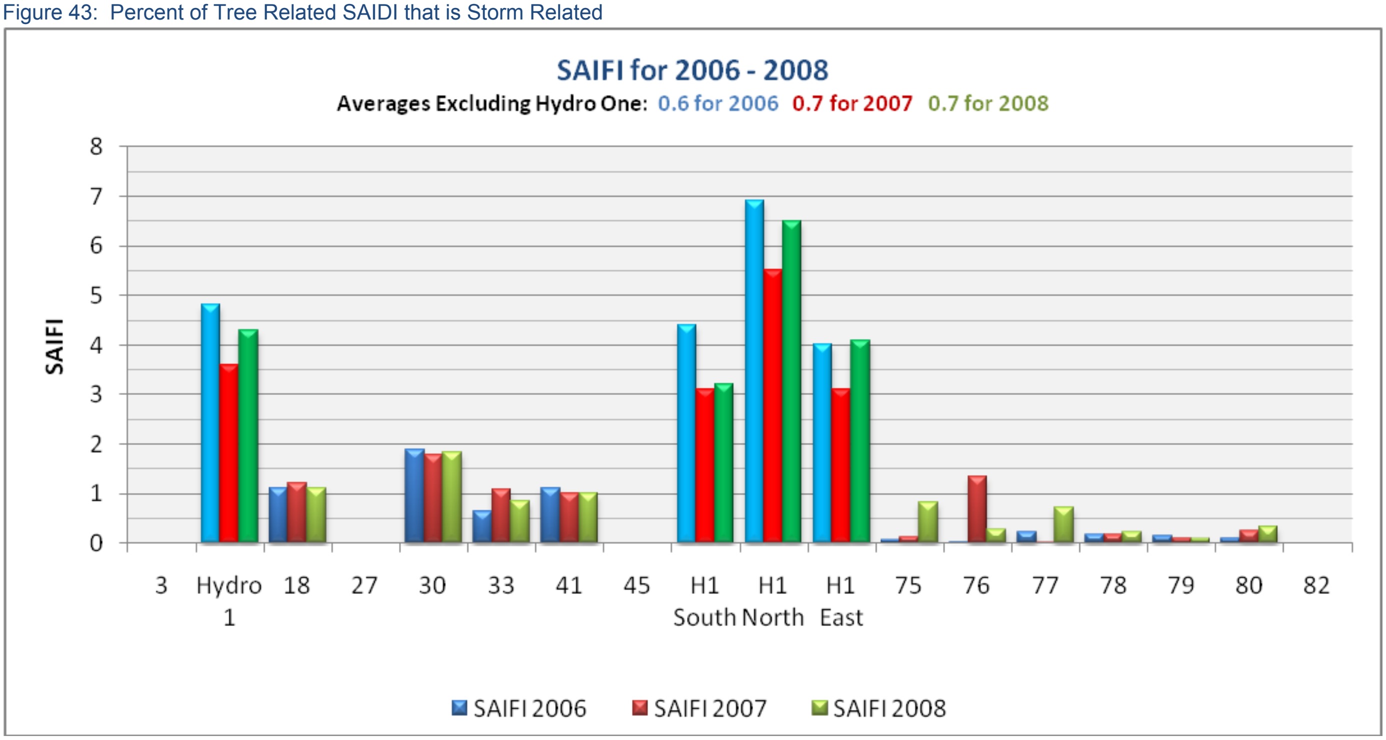


Figure 44: SAIFI for 2006 - 2008

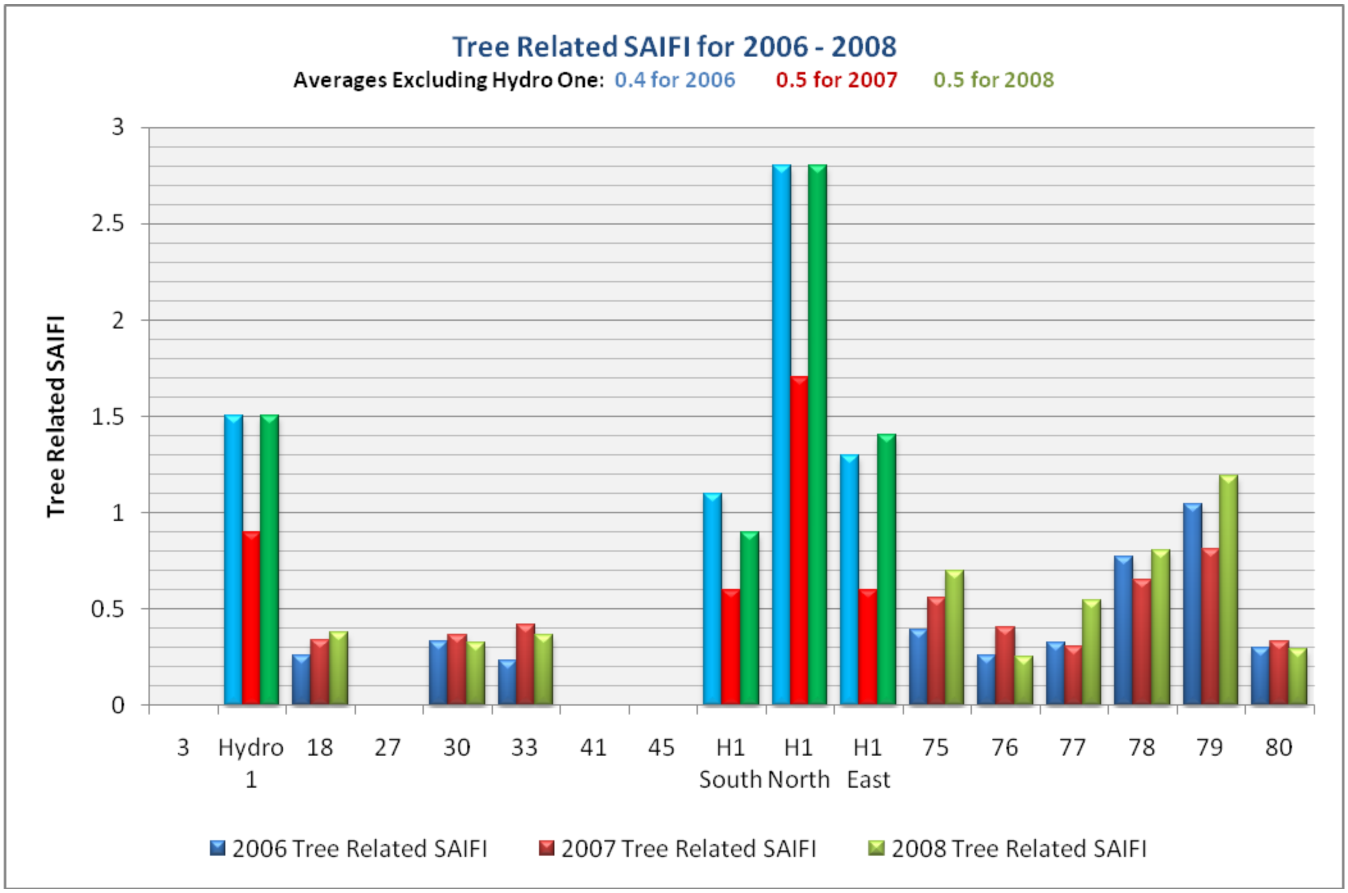


Figure 45: Tree Related SAIFI for 2006 – 2008

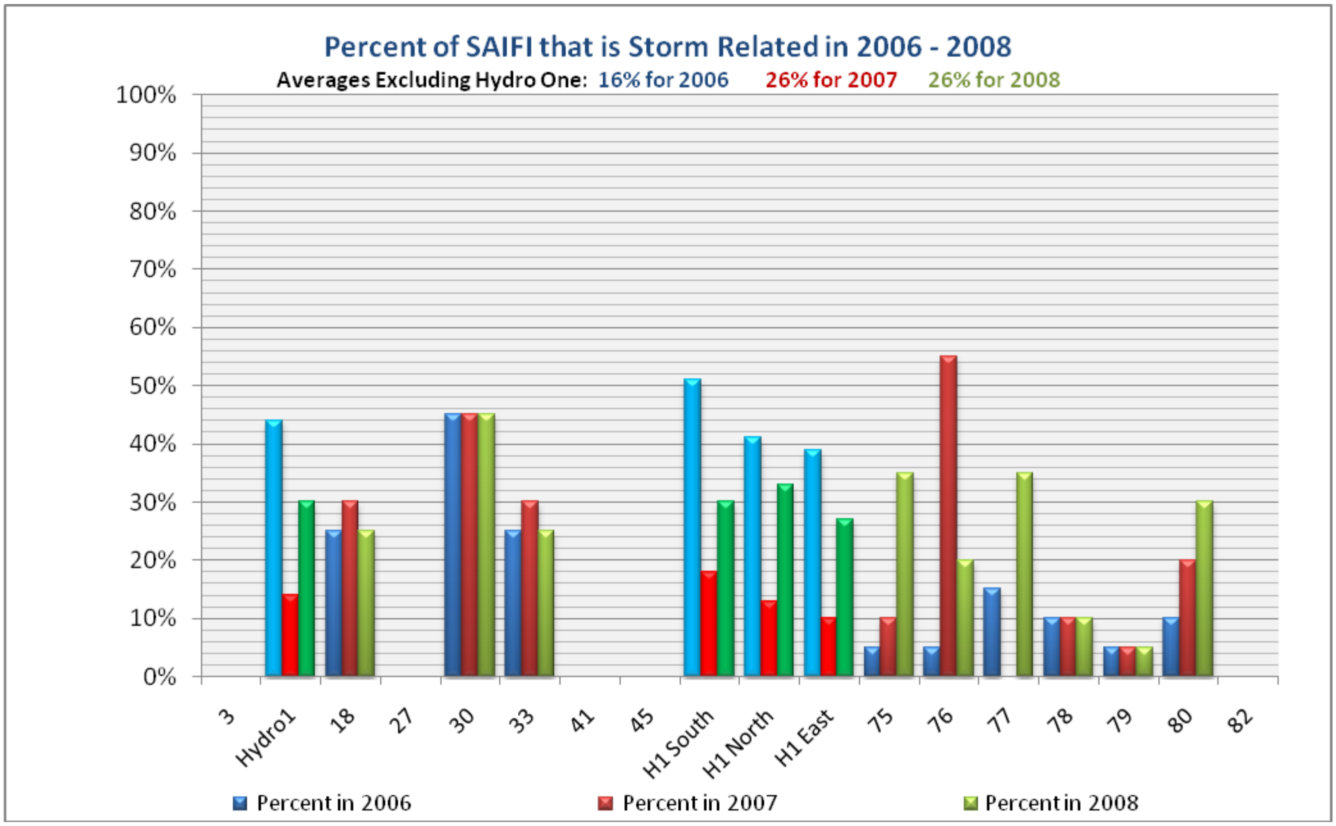


Figure 46: Percent of SAIFI that is Storm Related in 2006 - 2008

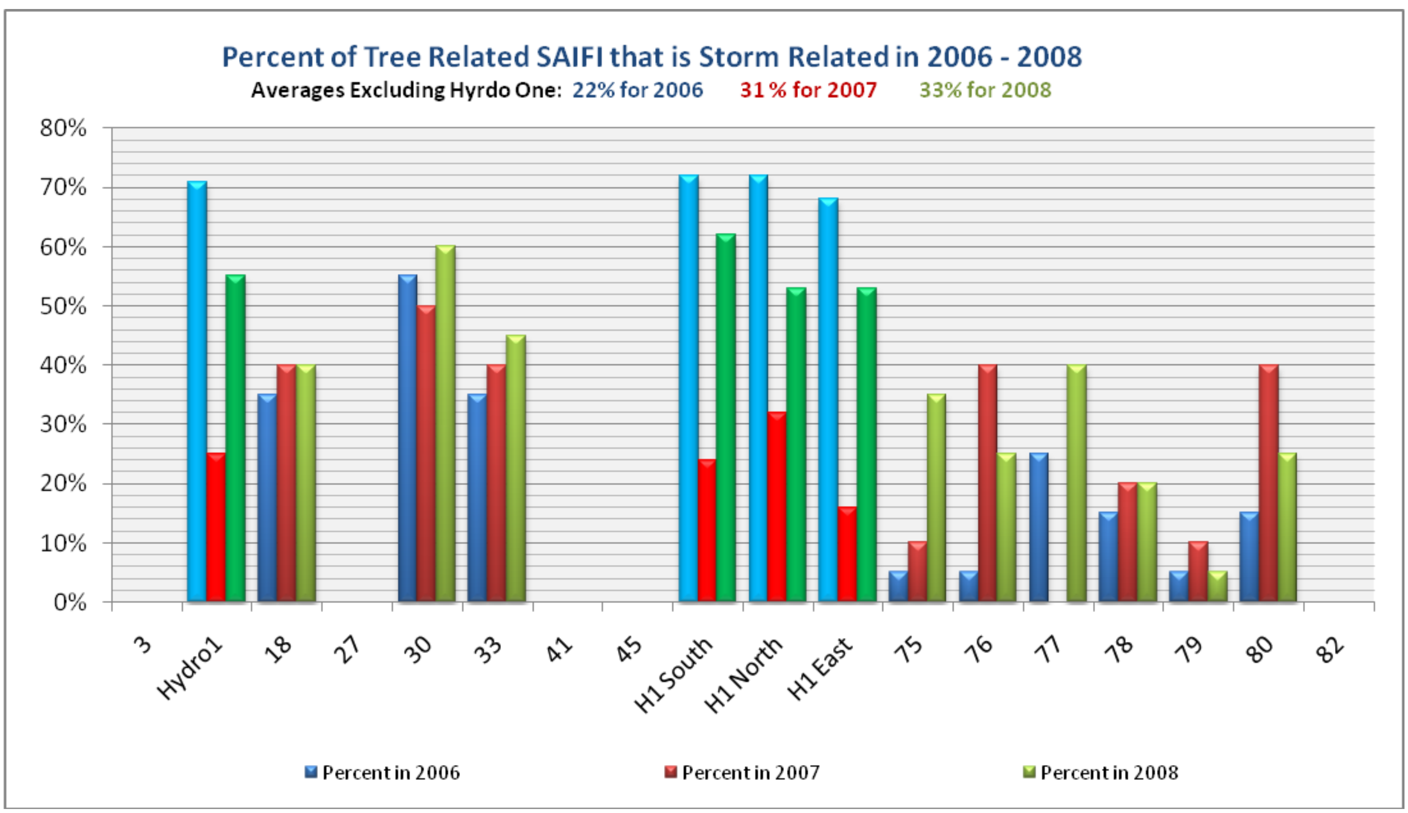


Figure 47: Percent of Tree Related SAIFI that is Storm Related in 2006 - 2008

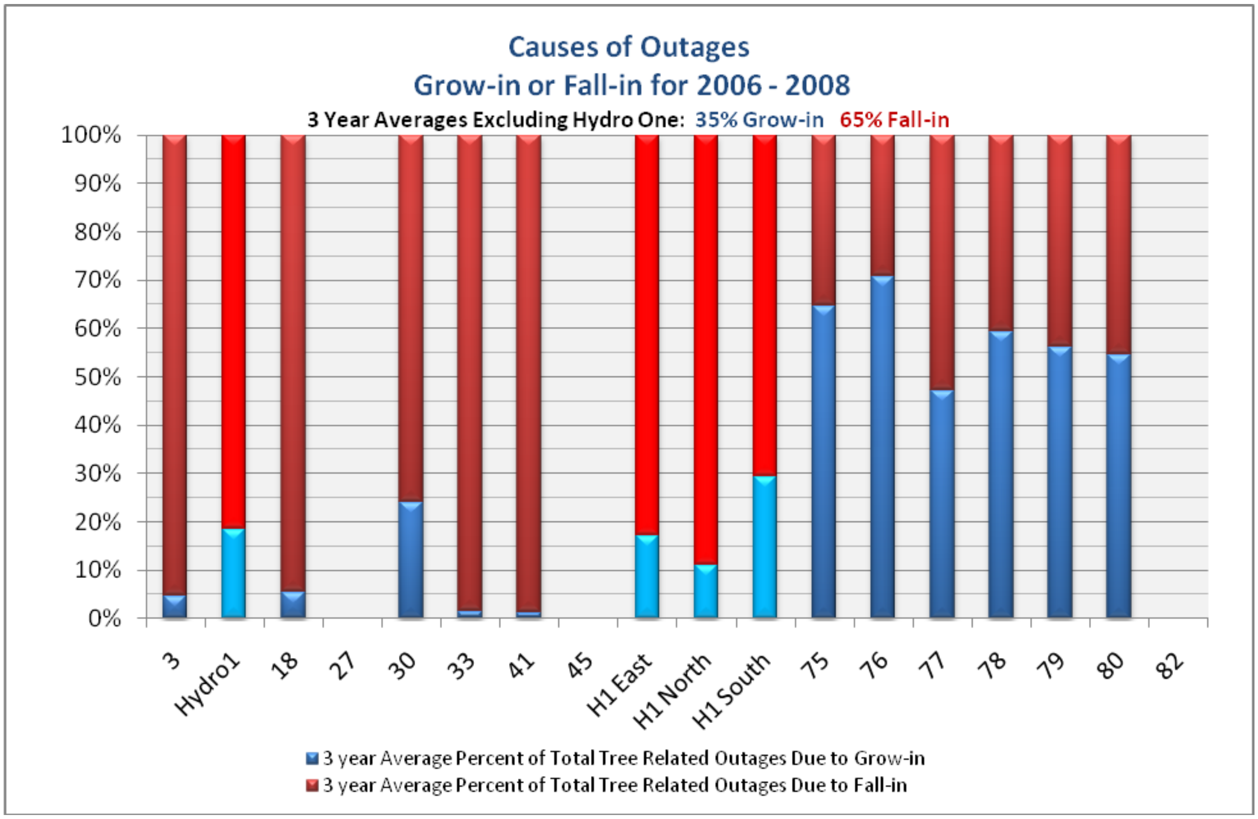


Figure 48: Causes for Outages – Grow-in or Fall-in for 2006 – 2008

Utility Vegetation Management Industry Intelligence & Ongoing Data Collection and Analysis

2011-2012 Cumulative Distribution CN Utility Benchmark Survey Report

Prepared by

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INTRODUCTION

ABOUT THIS PUBLICATION

Utility Vegetation Management (UVM) is best described as "the cost-effective and environmentally correct practices and efforts of a utility to prevent any vegetation from conflicting with the safe and efficient delivery of electricity." Trees and vegetation have a significant impact on all electric companies who have exposed overhead power systems. In many areas, trees represent the single largest threat to electric service reliability and resulting mitigation efforts representing one of the largest maintenance expenses incurred by electric utilities.

The people at CN Utility Consulting, Inc. (CNUC) are pleased to provide you with these benchmarking results in the hopes to improve or validate utility vegetation management activities.

This report represents the present "state of utility vegetation management" for distribution UVM of 22 companies in North America. Currently, CNUC is receiving data from additional companies and as more data is collected this report will be updated and distributed to you to reflect the changes. The survey is open to all electric distribution companies. CNUC believes that the information contained in this report will be helpful to all utility arborists interested in identifying trends, best practices and opportunities for improvement.

It should be noted, however, that benchmarking results are subject to interpretation and also influenced by local considerations. This is particularly true when it comes to utility vegetation managements programs. It is a fact that that each utility must deal with a litany of internal and external influences that each have a unique impact on operating procedures and statistical results. For example, utility companies in Oregon are now required to establish and maintain specific clearances between vegetation and conductors. This external mandate (promulgated by the Public Utility Commission) will obviously affect many indices, such as budget and scheduling methodologies. Bottom line, one shoe does not fit all when it comes to utility vegetation management programs. These differences should be taken into consideration when comparing your specific program with results presented in this report.

REPORT FORMAT

There are several unique features to this report. By understanding how this report is formatted, you will understand how to quickly navigate to the sections you are most interested in. You will also be able to verify that the correct information has been downloaded for your company. We hope that these instructions will help you have a rewarding experience with this preliminary report.

1. **Table of Contents:** The *Table of Contents* is linked so that you can quickly get to page of interest. A ***Click*** is all that is required.
2. **Table of Figures:** The *Table of Figures* are also linked and navigation is the same as for *Table of Contents*.
3. **Glossary of Terms:** The *Glossary of Terms* appears at the end of the report. It is the same glossary as the one attached to the distribution survey.
4. **Report Organization:** The report has the same organization as the survey. Each chapter corresponds to a section of the survey and has the same title.
5. **Questions in Survey and Report:** The questions, quoted directly from the survey, are displayed immediately preceding the graph, table or figure. In some cases the question may be on one page and the figure on the next.
6. **Question Integration with Figures:** If a question yielded data that is displayed on several graphs, there is an **underlined hyper-link** in bold lettering above the graph that directs you to the question the data was collected from. Once again, simply ***Click*** on the hyper-link to see the wording of the question.
7. **Question Integration with Figures (more than one question):** Some figures were generated by integrating information from more than one question. Information as to which questions were used to calculate statistics will be indicated above the graph in hyper-link(s). A ***Click*** on the hyper-link(s) is all that is required.
8. **Code Numbers:** Charts that include company data are sorted in numerical order to aid in locating your company's data.
9. **Currency Conversions:** Conversions from Canadian dollars to USD were done by dividing Canadian dollars by exchange rates. The annual exchange rates were taken from the following site:
   http://www.irs.gov/businesses/small/international/article/0,,id=206089,00.html
   Annual Exchange rates used were: **2005**, 1.212; **2006**, 1.180; **2007**, 1.117; **2008**, 1.109; **2009**, 1.187; **2010**, 1.072; **2011**, 1.029
10. **Unit Conversions:** Kilometres and square kilometres have been converted to miles and square miles, respectively.
11. **Conversions to Metric:** If you would like to see any data represented in Canadian Dollars and/or kilometres, we will gladly convert desired graphs into that format.
12. **Unused Data:** If we were unable to interpret the data submitted, or if the data was presented in a way that was not comparable to other utilities, it was omitted.
13. **Data Changes:** Changes in numerical data was done by CNUC if there was an email interchange between CNUC and the benchmarking participant to clarify responses. Other instances that resulted in altering data were if the comments about numerical inputs indicated that the figures was derived in a manner different than required and a numerical increase or decrease was also indicated.

14. **Small Value Notations:** If a value was too small to register as a bar on a chart, the value itself is indicated in place of a bar.
15. **Respondent Commentaries**: Many of the survey questions and replies do not translate into data, because they are opinions. For that reason much of what you will read is actual commentary by participants. Comments have only been edited to remove references to the utility company or name of contractor. We have taken the liberty of eliminating redundant answers to aid in reading. If many textual answers are redundant, we have quantified the responses for you, sometimes in a graph. Spelling and punctuation have been corrected as needed.
16. **Square Brackets**: Square brackets found in commentary tables are editorial additions made by CN Utility Consulting.
17. **Question Numbers:** Questions are numbered as they appear in the survey #1 – 277.
18. **Your Responses:** You will be given a copy of your responses to compare with the graphs and tables. Questions and question numbers will be included with your responses.
19. **Accuracy Check:** Looking at graphs that have your company included will be a way to check the accuracy of the representation of your company. If the information on the graph seems questionable for your company, please email ncohn@cnutility.com or call 1-707-827-1397 and ask for Nina Cohn. We will gladly change any information that was incorrectly input into the survey or was downloaded incorrectly. Remember that all monetary information is reported in US Dollars. Canadian Dollars have been converted using annual exchange rates.
20. **Your Company Code:** To check your company's responses you will need your company code. This should be displayed on your responses.

COMPANY TYPE

The types of companies participating in the CNUC Benchmarking Study included State Owned, Municipality or Public Utility Districts, Utility Cooperatives and Investor Owned Utilities. At the point in time, only 22 companies have answered this question.

Question #2: Type of utility (Please check one)

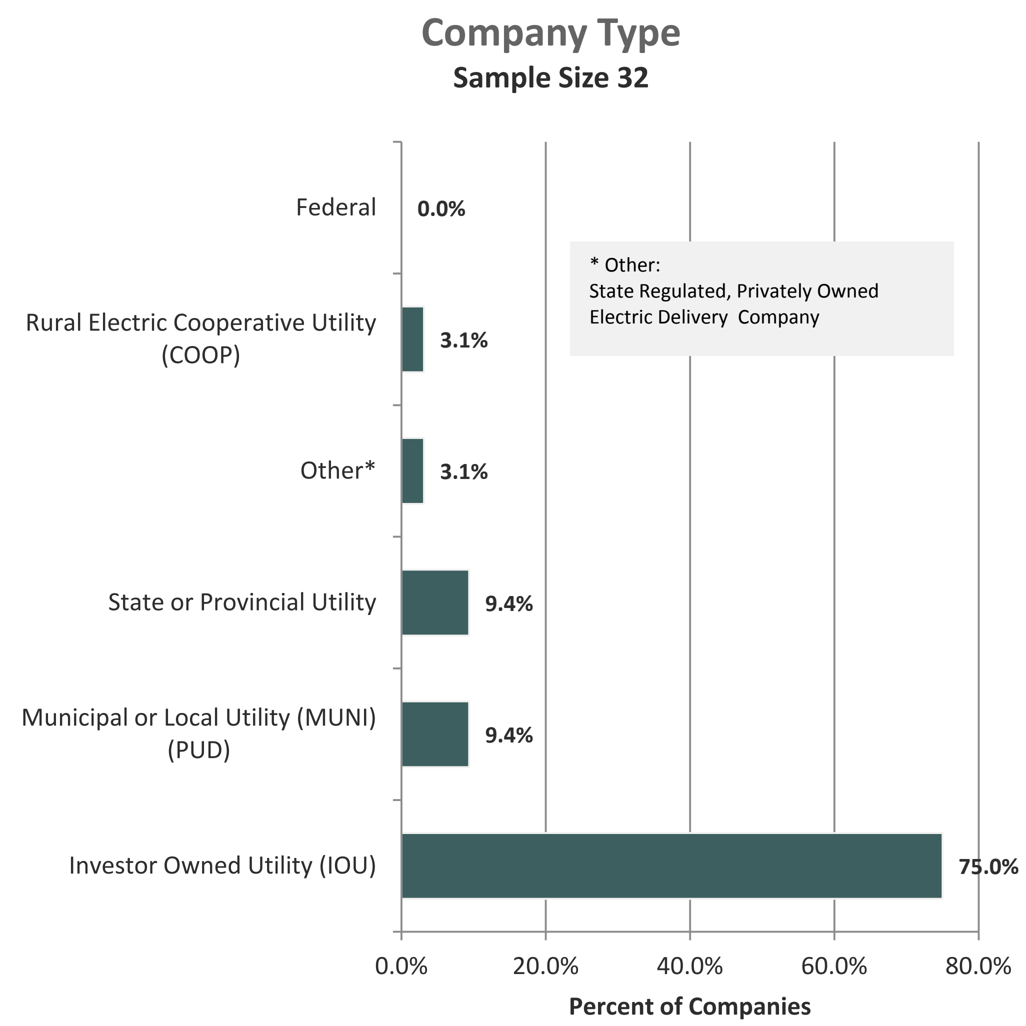

Figure 1: Company Type

UTILITY TYPE

The types of utilities participating in the CNUC Distribution Benchmarking Study are *Transmission & Distribution; Distribution Only; Transmission, Distribution and Generation* and *Transmission, Distribution & Generation* utilities. At this point in time, only 22 companies have answered this question.

Question #3: Is your utility a ______________ (Please check one)

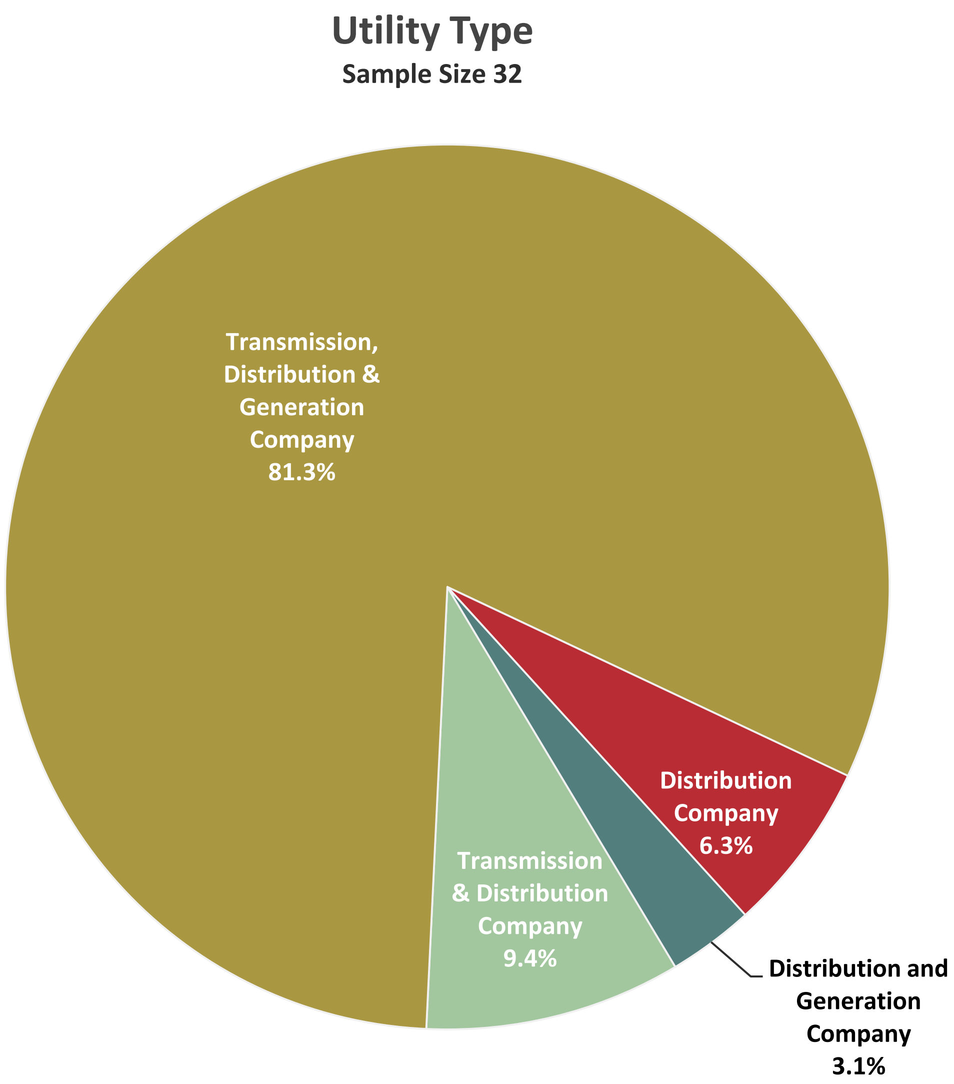

Figure 2: Utility Type

SERVICE TERRITORY

The following chart has been made to compare company service areas.

Question #5: What is the total area of your service territory?

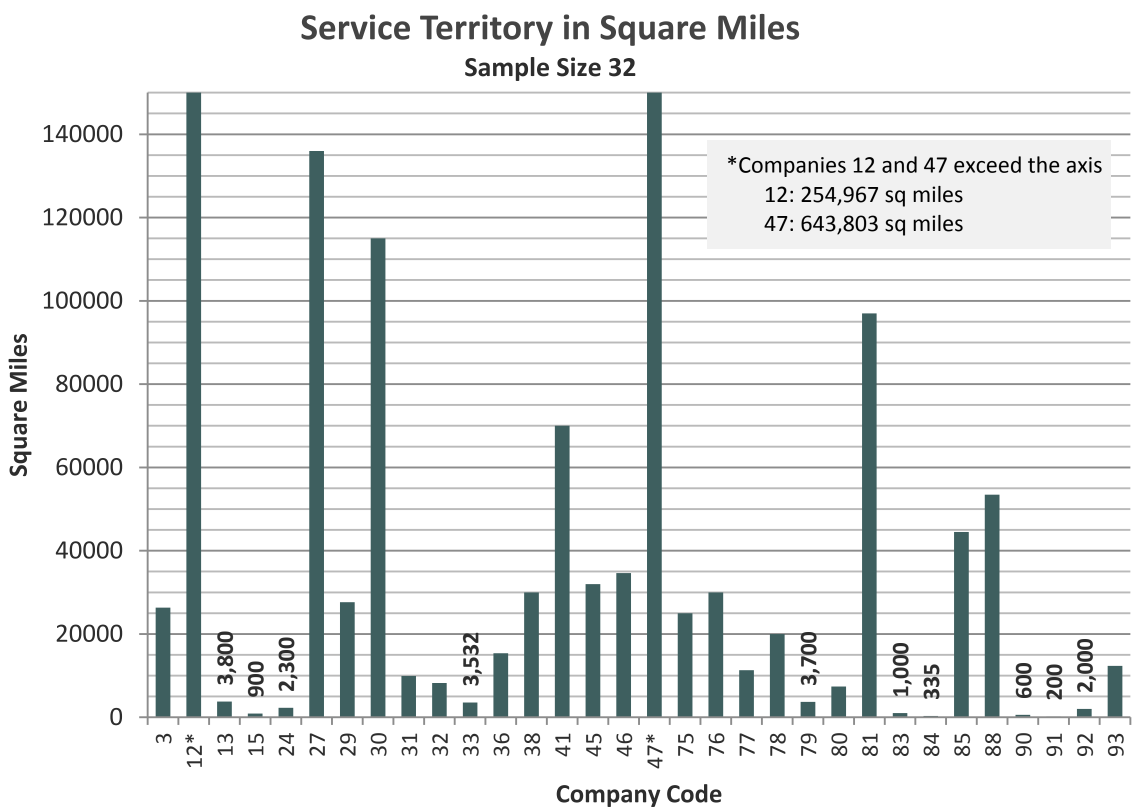

Figure 3: Service Territory Area

Service Territory Description

The following graph gives the service territory breakdown for each company (next page, Fig. 4)

Question #6: Description of service territory (Please *approximate* in percentages). NOTE: These percentages are only intended to categorize customer density and may not reflect your company's definition of Urban, Suburban, Rural and Remote.

Note: **Urban** areas are defined as “more than 50 customers per line mile,” **suburban** areas are defined as “25 to 50 customers per line mile,” **rural** areas are defined as “between 5 to 25 customers per line mile” and **remote** areas are defined as “less than 5 customers per line mile.”

Averages for *urban, suburban, rural* and *remote* are similar to 2006 results.

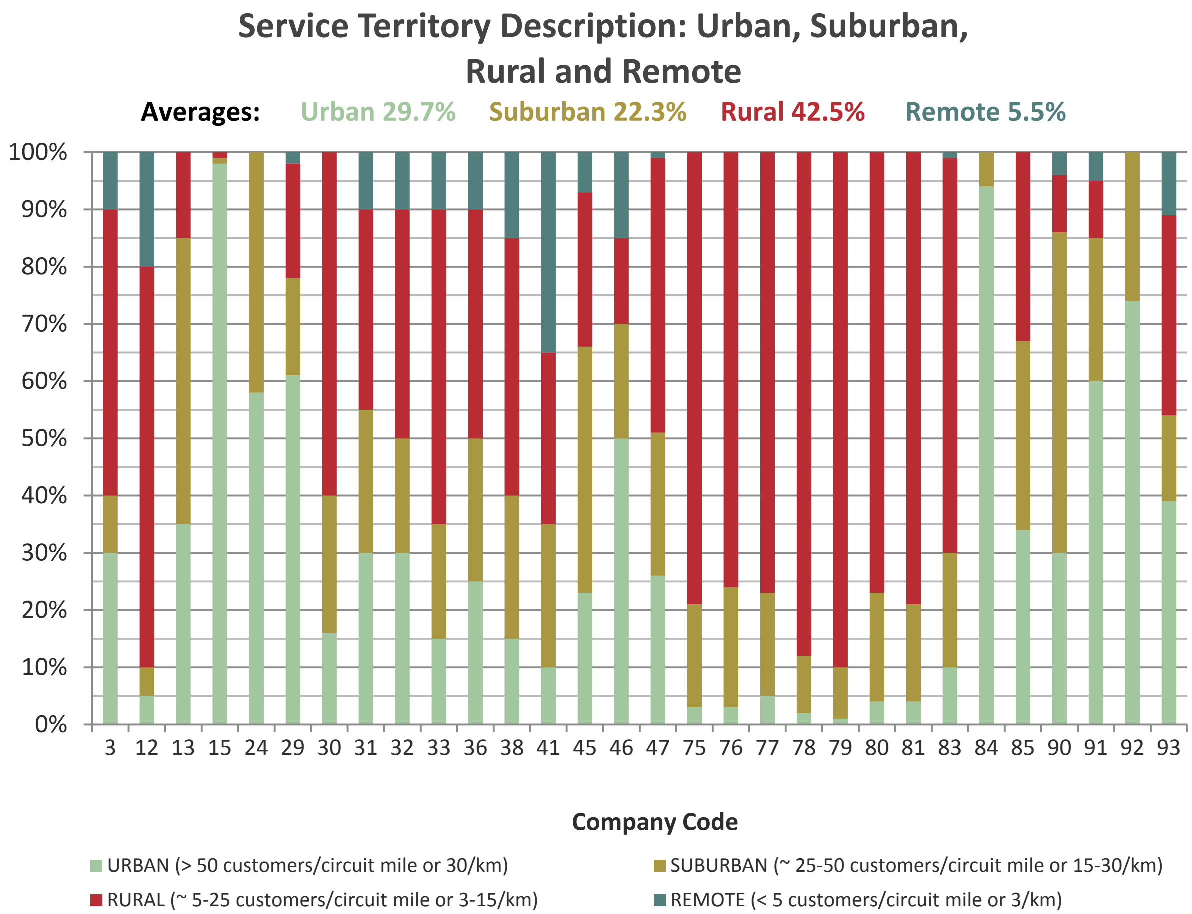

Figure 4: Service Territory Description by Population Density

ELECTRIC CUSTOMERS

Total Number of Electric Customers

Two charts have been used to depict these values. The first chart shows the total number of electric customers each company provides with electrical service. The second chart examines the composition of the electric customer base (residential, industrial, agricultural, or other). The comment table defines what constitutes "Other" electric customers.

Question #7: Please list the number of electric customers you serve by classification. NOTE: The sum of the first five responses should add to the total number of electric customers.

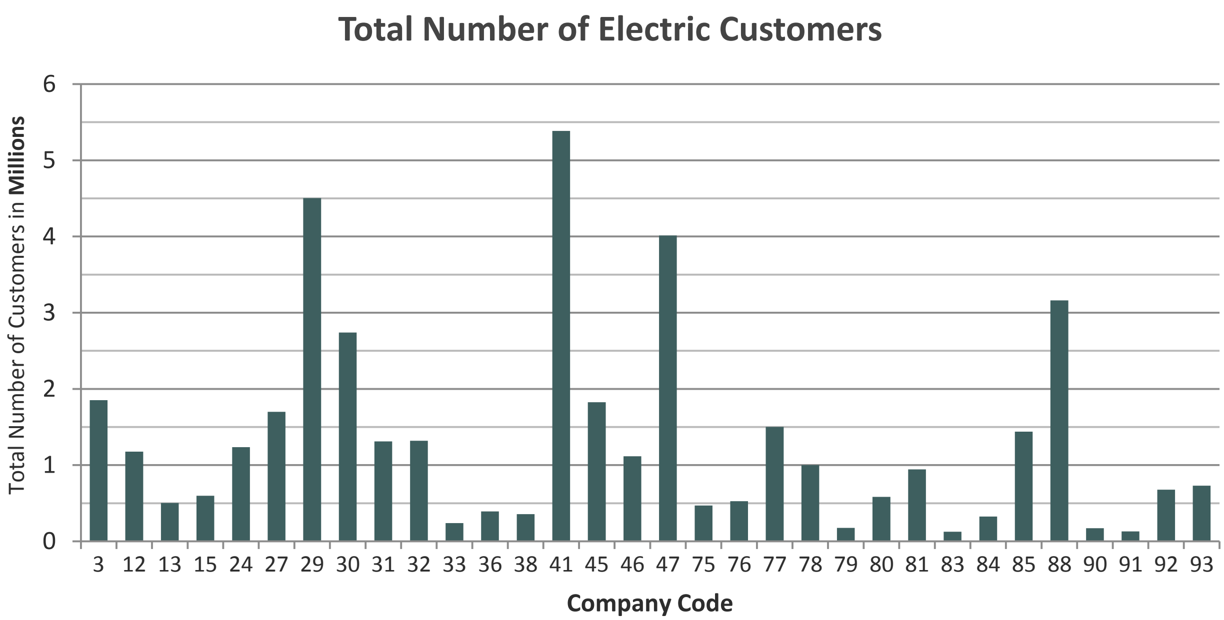

Figure 5: Total Number of Electric Customers

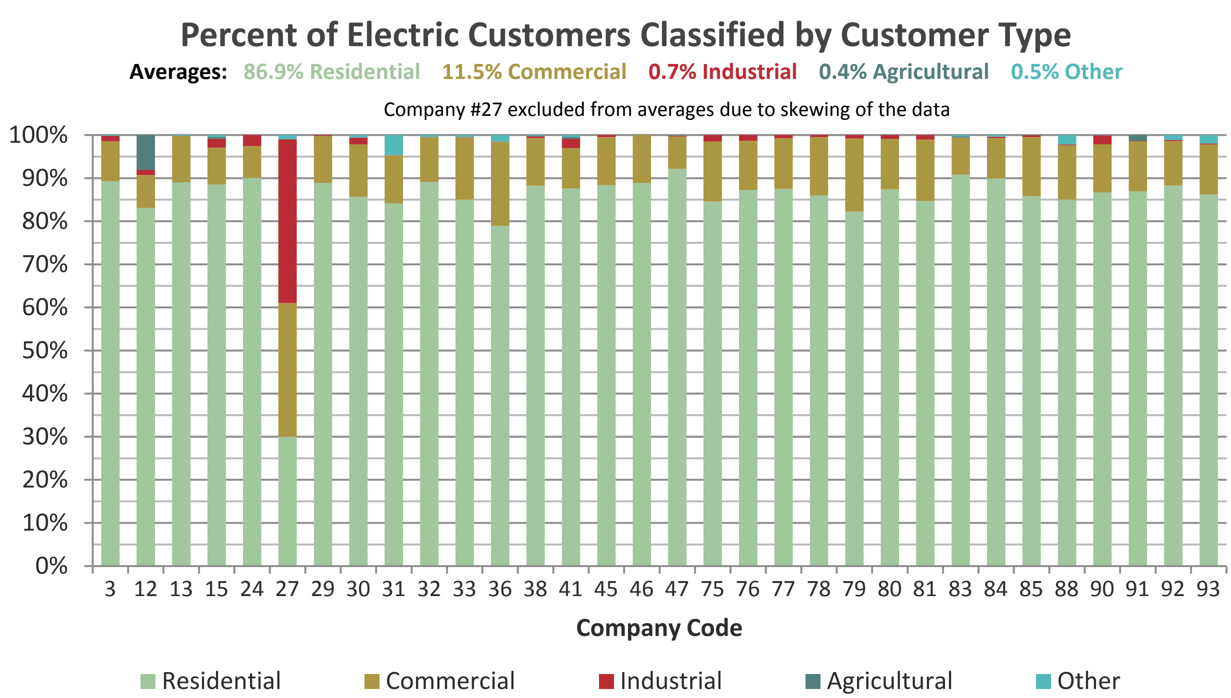

Figure 6: Percent of Electric Customers Classified by Customer Type

Other Classifications of Electrical Customers
Irrigation, street lighting, [utility's] own use
289-Other Public Authorities; 610-Streetlighting
Street & Traffic Light
Public lighting systems and municipal distribution systems.
Street lights, public authorities, sale for resale
Street Lighting
Governmental, Lighting and Signal
Outdoor Light

Figure 7: Other Classifications of Electrical Customers

Electric Customers Served by Overhead versus Underground Lines

Two charts have been used to depict these values. The first chart shows the total number of electric customers served by overhead lines versus underground lines. The second chart examines the percent of the electric customer base served by overhead lines and those served by underground lines.

Question #8: How many customers are served by overhead and how many are served by underground? NOTE: The sum of these two responses should add to your total number of electric customers supplied in the previous question.

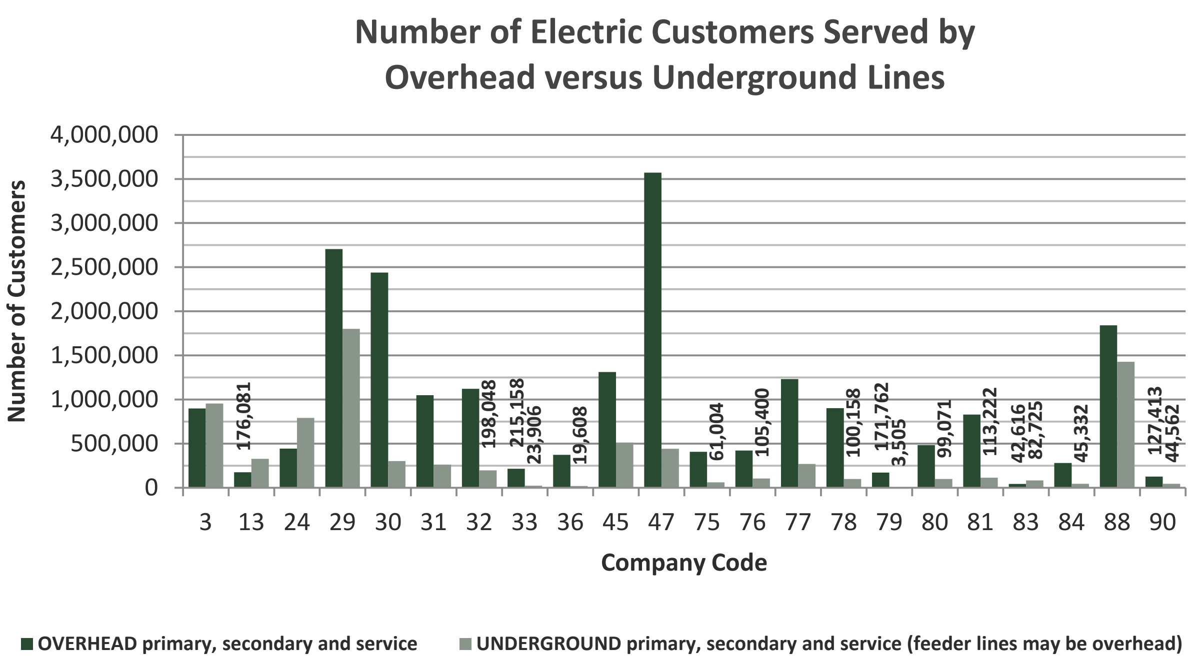

Figure 8: Number of Electric Customers Served by Overhead versus Underground Lines

Statistics calculated with data collected from **Question #8**.

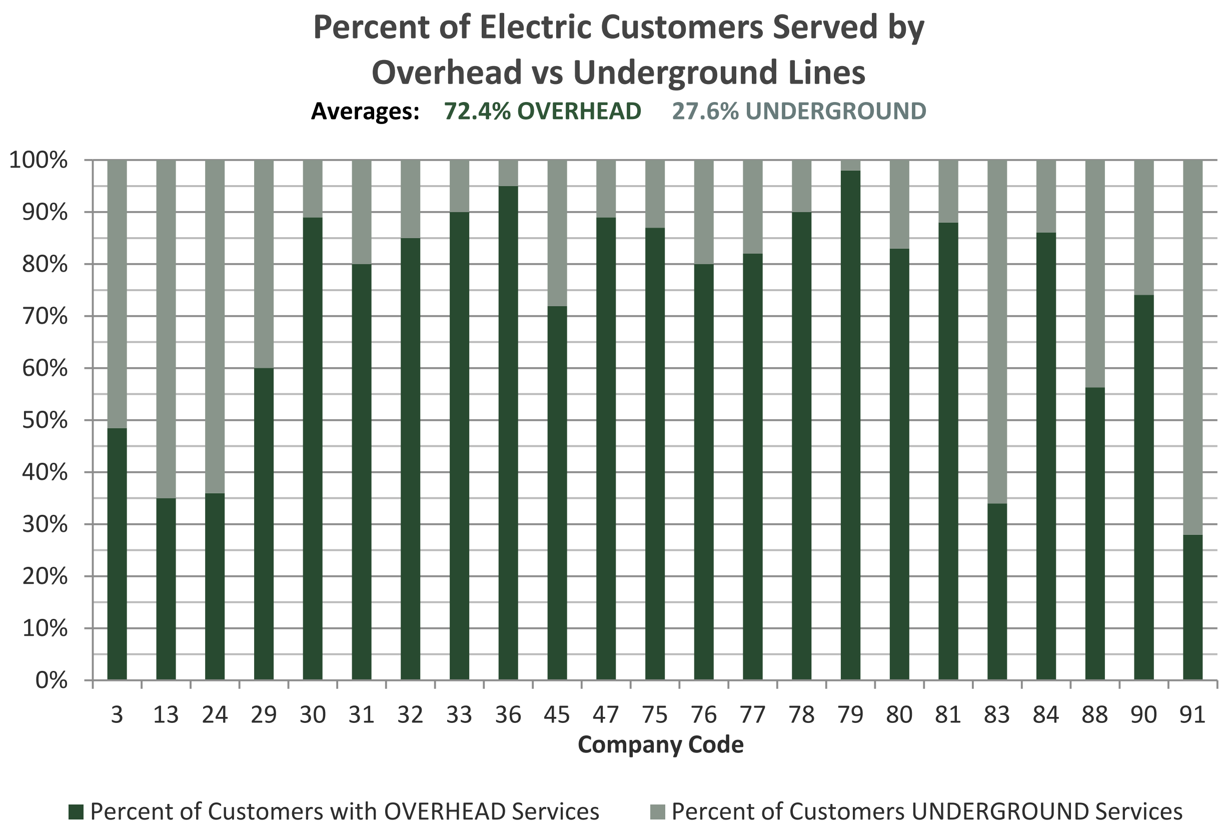

Figure 9: Percent of Electric Customers Served by Overhead versus Underground Lines

OFF-ROAD AND ON-ROAD ACCESS

Two charts have been used to depict these values. The first chart shows the percent of overhead lines that are off-road versus on-road. The second chart categorizes the percent of the off-road access into *Limited, Steep, Flat, Marshland* or *Other*.

Percent of Off-Road vs. On-Road Access

Question #10: What percent of OVERHEAD distribution pole km/mi are_______?
NOTE: Percents of off-road and on-road (two boxes below) should add to 100%

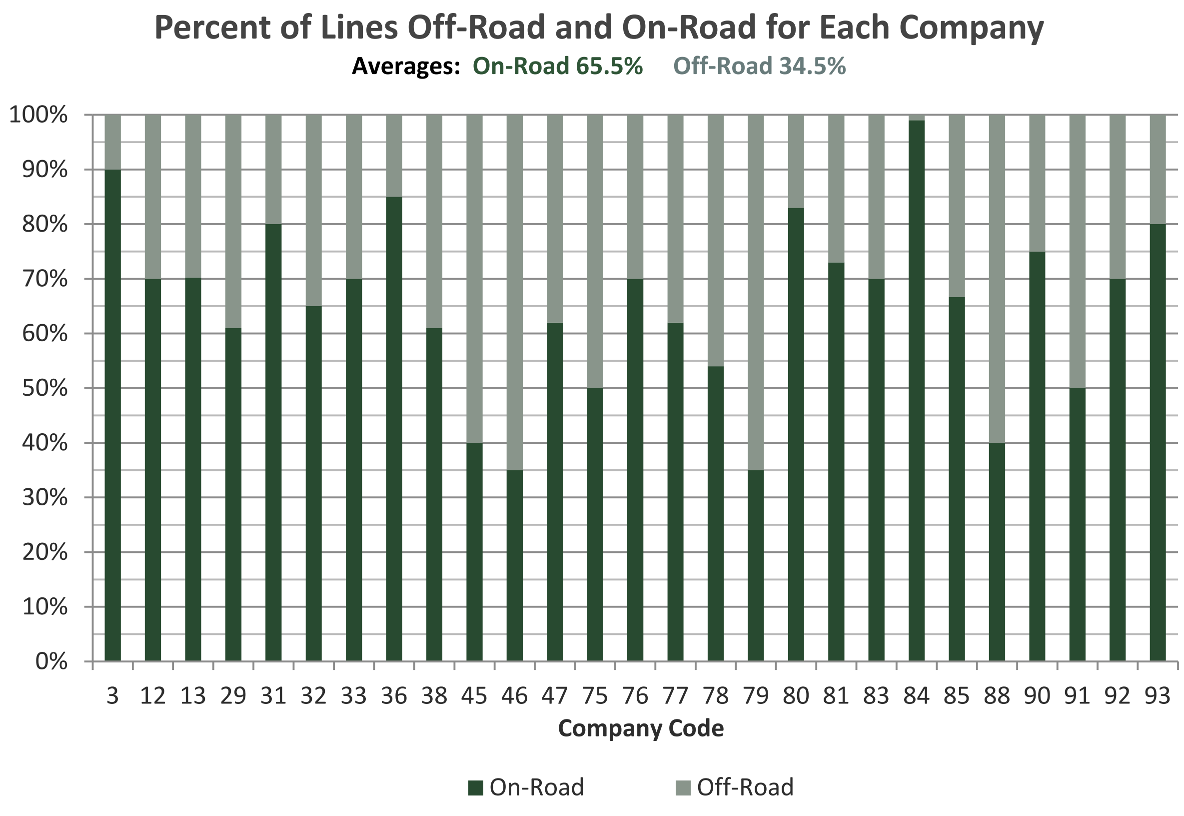

Figure 10: Percent of Lines Off-Road and On-Road for Each Company

Access to Off-Road Distribution Lines Categorized by Geographical Attributes

Question #11: By what percentages would you divide up your OFF-ROAD distribution pole km/mi according to geographical differences?

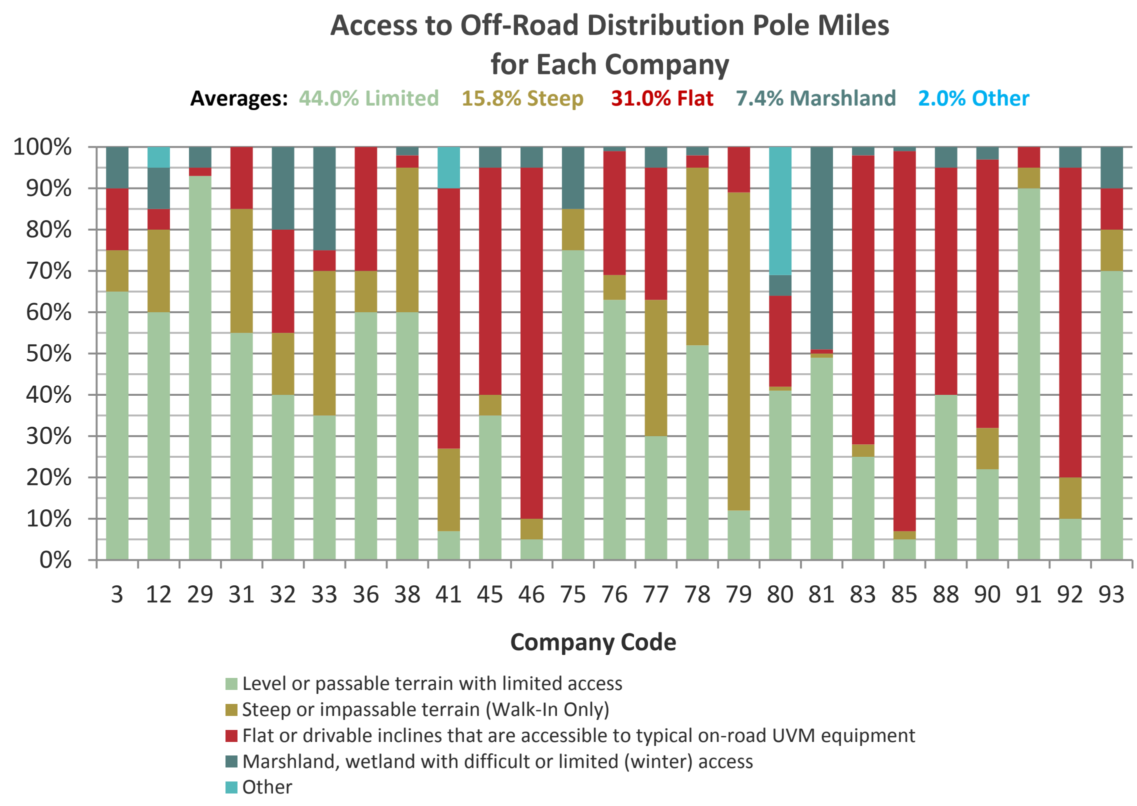

Figure 11: Access to Off-Road Distribution Pole Miles for Each Company

Comments on Access to Off-Road Distribution Pole Miles
Backyard Easements that must be accessed on foot.
Cropland
Boat and helicopter access only

Figure 12: Comments on Access to Off-Road Distribution Pole Miles

PERCENT OF CUSTOMERS REQUIRING UVM ON THEIR PROPERTY

Two charts are given to depict this data. This question dealt not only with the number of customers impacted by UVM, but it also investigated the frequency that UVM was performed on their property.

Question #12 & 13: How many customers (or meters) on your distribution system require vegetation management on their property on a _______________ basis? NOTE: Responses were either given as number of meters (exact) or as percentages (estimates).

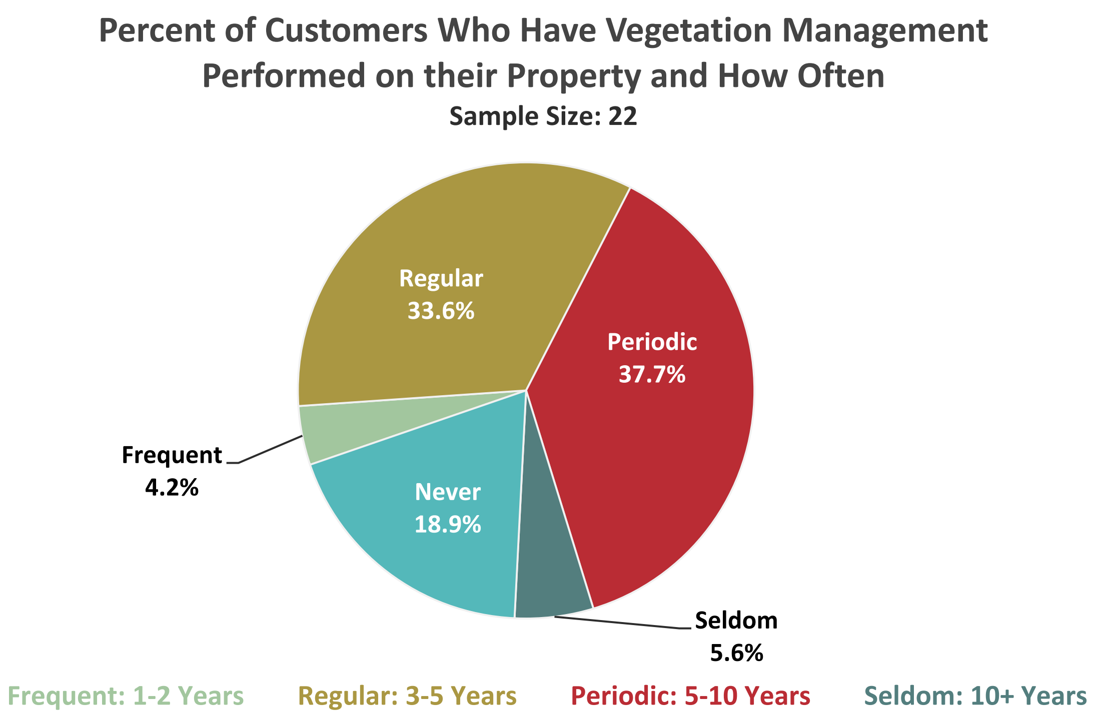

Figure 13: Percent of Customers Who Have VM Performed on their Property and How Often

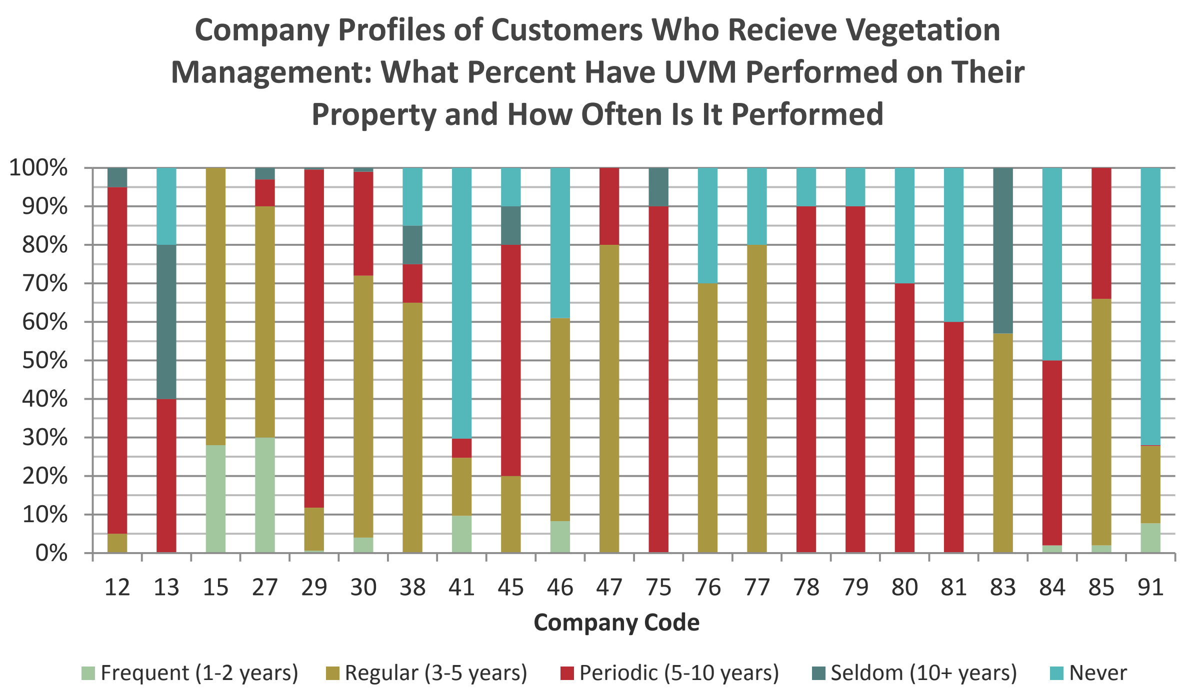

Figure 14: Company Profiles of Percent of Customers Who Have VM Performed on their Property and How Often

Data Discussion on Customers Requiring UVM on Their Property:

Several conclusions can be drawn from the analysis of the data:

- A large proportion of utilities (41% of companies) perceive their workload as 100% of their customers, even though a good percentage of their customers have underground services and many customers only have service wires on their property. Many utilities do not prune for service wires.
- Given the possibility that 100% of customers do require some UVM on their property, 66.1% of customers require work infrequently (the sum of the percentages of the *Periodic, Seldom* and *Never* categories). This leaves a reported **33.9% of the customer base on average requiring regular UVM performed on their property.**
- It is possible, even probable, that vegetation managers have not calculated their actual workload in terms of customer base and that the average percent of customers who require UVM is substantially less than 33.9%.

AVERAGE ANNUAL COST OF UVM PER CUSTOMER

Reported Annual Cost per Customer for UVM

Question #14: Do you know the average annual cost of UVM per customer (or meter)?

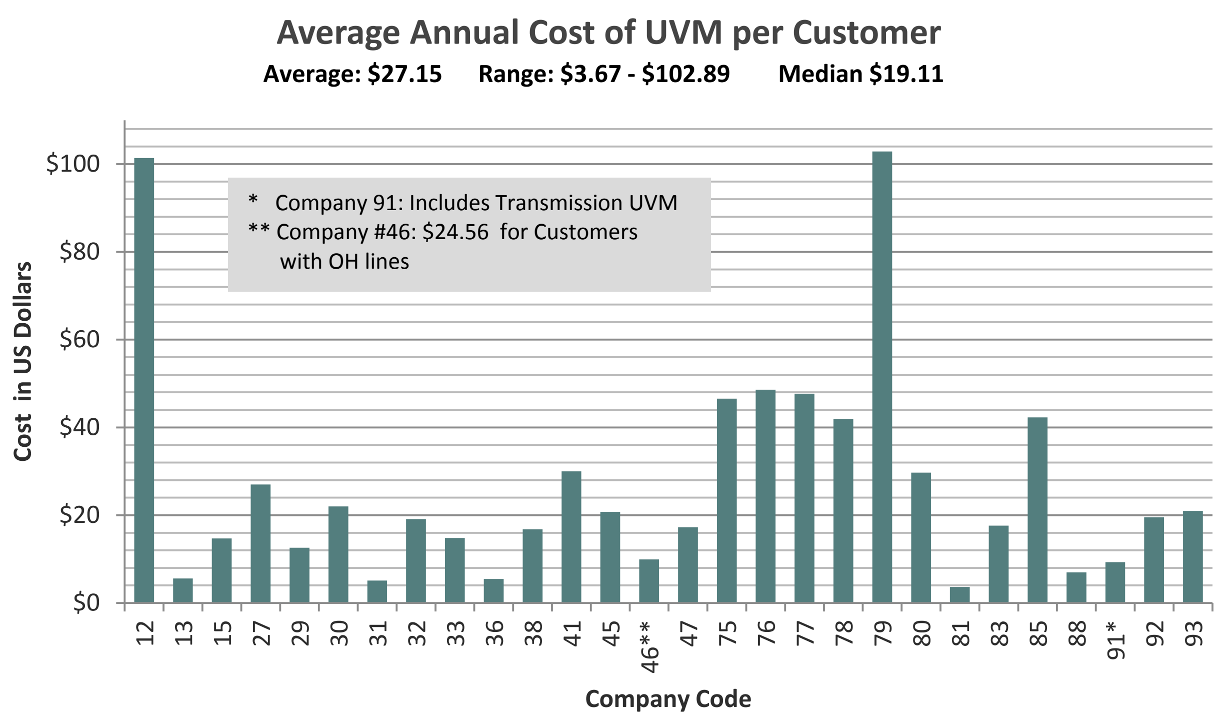

Figure 15: Average Annual Cost of UVM per Customer

Reported Versus Calculated Annual Cost per Customer for UVM

Companies that reported annual cost per customer for UVM in the previous question and also reported total number of electric customers and total cost of UVM were included on the graph below.

Statistics for the reported cost per customer was collected in **Question #14**. The calculated statistic was derived from data collected in **Question #7** and **Question #96.**

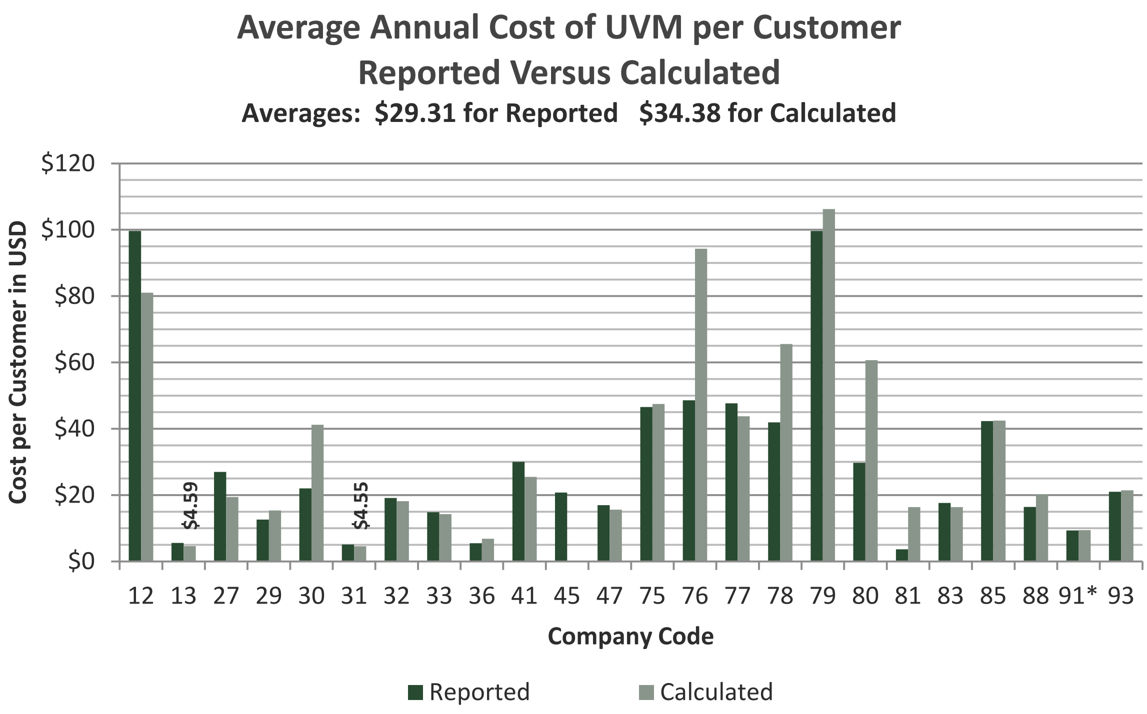

Figure 16: Average Annual Cost of UVM per Customer Reported Versus Calculated

DISTRIBUTION SYSTEM VOLTAGES

Each company gave the voltages present in their distribution system and the breakdown by company is on the following table (Fig. 16, below).

Question #15: List the various voltages found in your distribution system (0kV-59kV)

Voltage on Distribution Systems by Company								
Company Code	**0 - 250 Volts**	**250 - 999 Volts**	**1 kV - 5.99 kV**	**6 kV - 9.99 kV**	**10 kV - 19.99 kV**	**20 kV - 26.99 kV**	**30 kV - 39.99 kV**	**40 kV - 59 kV**
3			4 kV		12 kV	25 kV	34 kV	
12			4.16 kV	8.32 kV	12.51 kV 13.8 kV	22.8 kV 25 kV 27.6 kV		44 kV
13			4.16 kV		12.47 kV			46 kV
15			4 kV		12 kV	21 kV		
24			4 kV		13 kV		34 kV	
27			2.4kV 4.8kV	7.2kV	12kV	25kV	345kV	
29			4.16 kV		13.2 kV	22.9 kV		
30		2.4kV Delta	4.160 GrdY/ 2.4kV		12.47 GrdY /7.2kV; 13.2 GrdY /7.62kV; 13.8 GrdY /7.96kV; 13.86 GrdY /8 kV	22.86 GrdY/ 13.2kV; 23.9 GrdY/ 13.8kV; 24 GrdY/ 13.86kV	34.5 GrdY/ 19.92kV	
31			4 kV		13 kV	25 kV	34 kV	
32			4 kV		15kV		35 kV	
33			4 kV		12.5 kV	23.9 kV		
36			4 kV		13 kV	25 kV	34 kV	
41	120/ 240V	277/ 480V	4 kV		12 kV 17kV	21 kV	34 kV	
45			2.4kV 4.8kV	7.2kV	14.4 kV		46.0 kV	
46			5kV		15kV	25kV	35 kV	
47	120-240V	600V	4 kV		12 kV	25 kV	34 kV	44 kV
75			4 kV		12 kV 13kV	25 kV	34 kV	
76			2.4kV Delta 4kV		12 kV 13kV	25 kV	34 kV	
77			2.4kV Delta 4kV	7 kV Delta	12 kV 13kV	23.9 kV	34 kV	
78			2.3 & 2.4kV Delta 4kV	7 kV Delta	12 kV 13kV		34 kV	

Voltage on Distribution Systems by Company (Continued)									
79			2.4kV Delta 4kV		12 kV		34 kV	
80			2.3 & 2.4kV Delta 4kV	7 kV Delta	12 kV 13kV		34 kV	
81			2.3 & 2.4kV Delta 4kV	7 kV Delta	12 kV 13kV	24.9kV 25kV		
83					12.47 kV			
84			2.4kV 4.2kV	6.9kV	13.8kV			
85			4kV		12 kV 13kV	23 kV 25kV	35 kV	
88			4 kV 3-phase	7.2 kV single phase 7.63 kV single phase	12.47 kV 3-phase 13.2 kV 3-phase	25 kV 3-phase 14.4 kV single phase	33 kV 3-phase	
90			4 KV		12KV			46KV
91	120V 208V 240V 277V 480V			7.2 kV	12.47 kV		34.5 kV	
92	120V 240V	600V		7.6kV	13.2kV			
93			4kV		13.2kV 13.8kV		34.5kV	

Figure 17: Voltage on Distribution Systems by Company

CIRCUIT MILES

Total Circuit Miles

Question #16: Please list the number of CIRCUIT miles/kilometres, including UNDERGROUND AND OVERHEAD lines, for each voltage interval. NOTE: CIRCUIT miles/kms are all miles/kms of line. This is a count of conductor miles/kms. For example, one pole mile of double-hung circuit is equivalent to TWO CIRCUIT miles, but one pole/span mile.

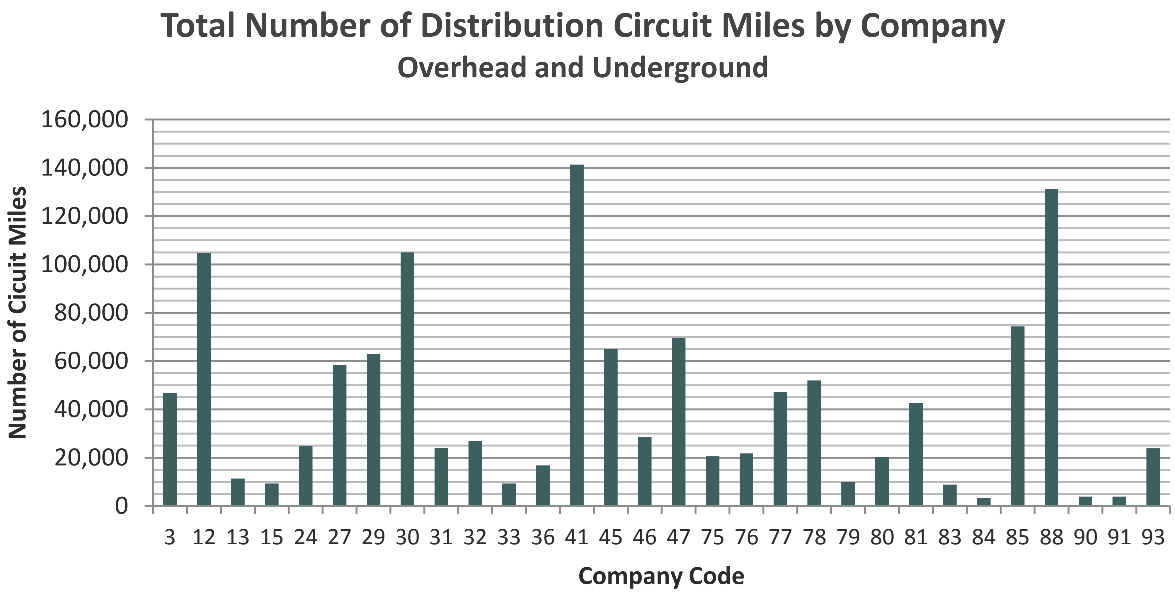

Figure 18: Total Number of Distribution Circuit Miles by Company

Percent of Total Circuit Miles at Each Voltage Class

The following graph (Figure 18, next page) calculated the *Percent of Distribution Circuits Miles at Different Voltage Classes* by adding up the total number of circuit miles in each voltage class for all companies and dividing by the total number of circuit miles reported by all the companies. Statistics were calculated using the data from **Question #16** (above).

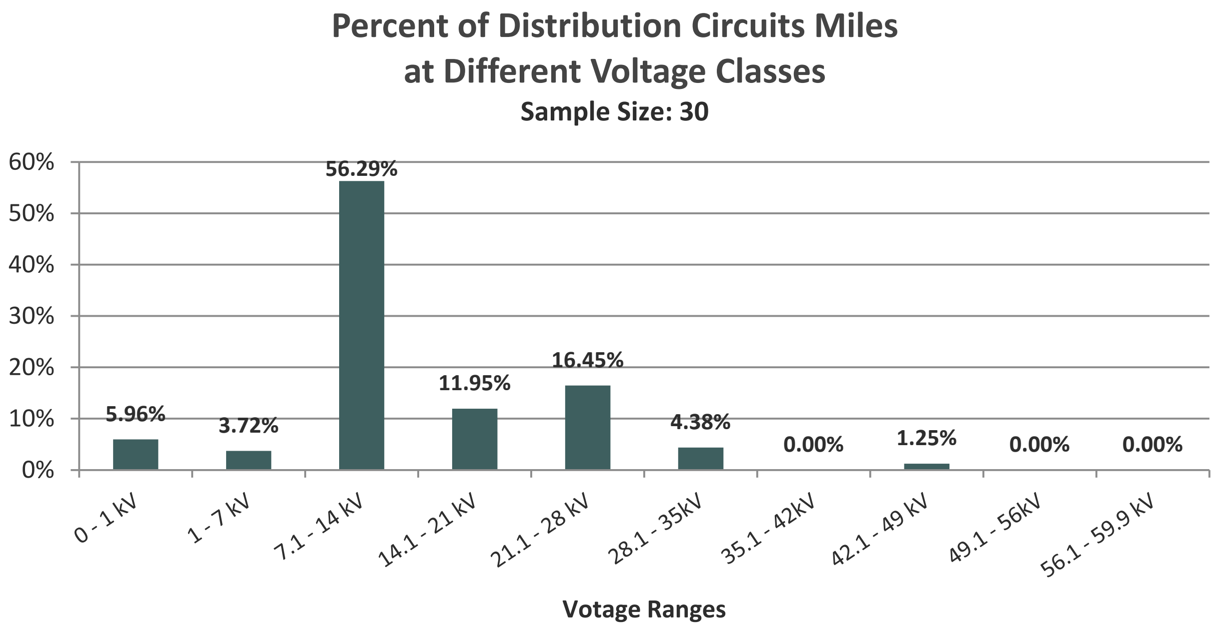

Figure 19: Percent of Distribution Circuits Miles at Different Voltage Classes

Overhead Circuit Miles

Question #18: Please list the number of OVERHEAD DISTRIBUTION CIRCUIT miles/kilometres for each voltage interval. NOTE: CIRCUIT miles/kms are all miles/kms of line. This is a count of conductor miles/kms. For example, one pole mile of double-hung circuit is equivalent to TWO CIRCUIT miles, but one pole/span mile.

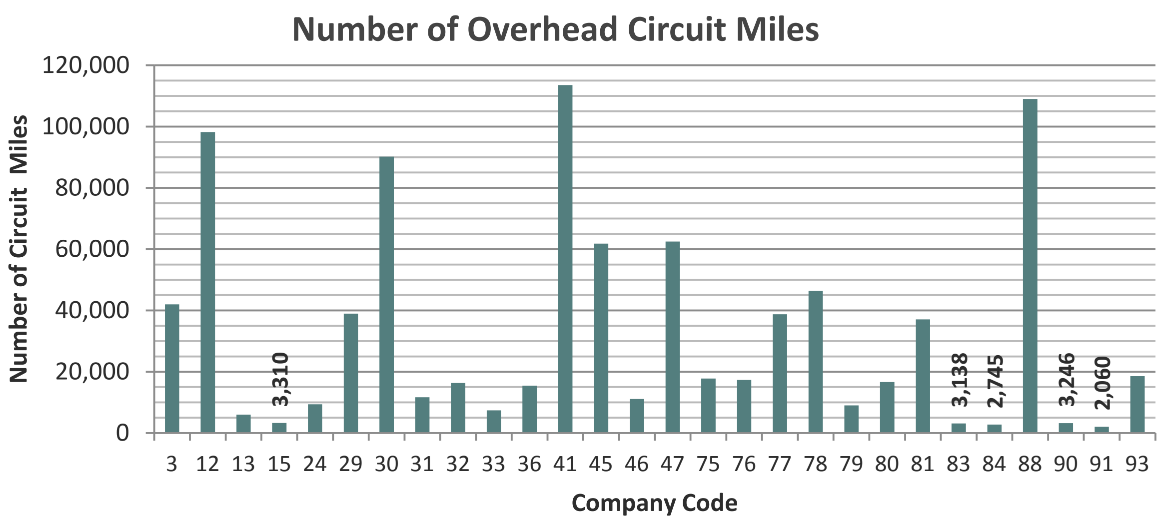

Figure 20: Number of Overhead Circuit Miles

Percent of Overhead vs. Underground Circuit Miles of Total Circuit Miles

Percent of Overhead was calculated statistic, using data from **Question #18** and **Question #16**.

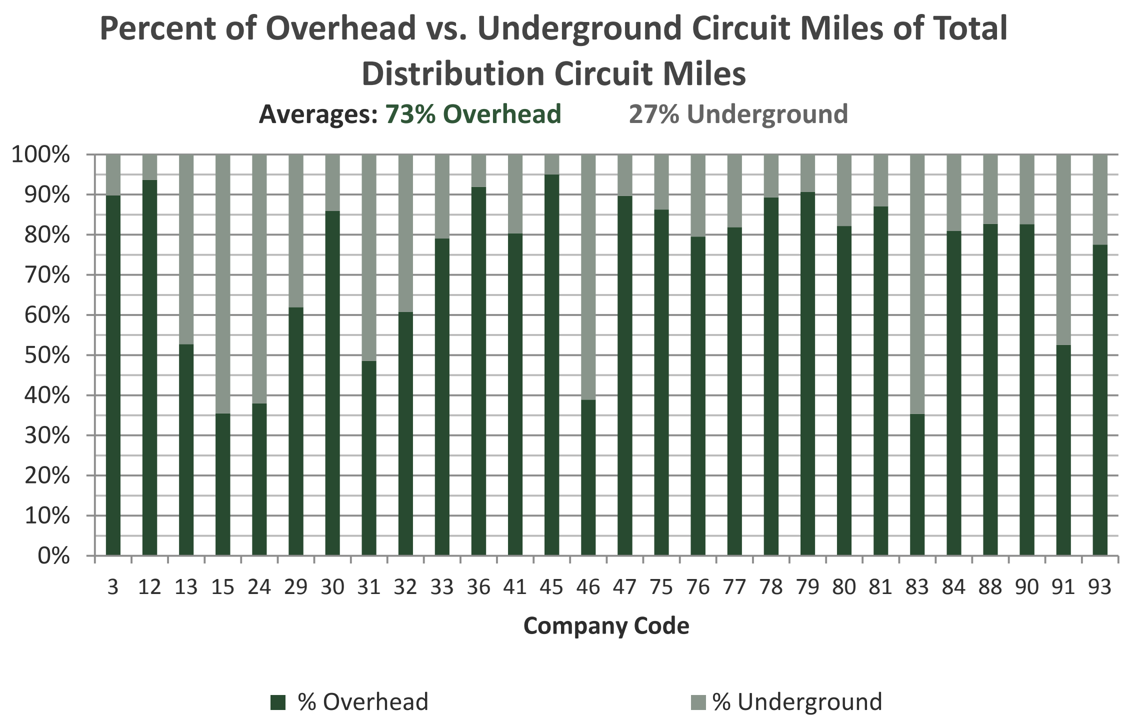

Figure 21: Percent of Overhead vs. Underground Circuit Miles of Total Distribution Circuit Miles

DISTRIBUTION SYSTEM POLE MILES

Question #20: Please list the number of DISTRIBUTION POLE/SPAN miles/kms of OVERHEAD lines for each voltage. All double and triple circuit miles and underbuilt pole/span miles should be represented with the highest distribution voltage on the pole. The following responses should represent all distribution pole/span miles.

NOTE: POLE/SPAN MILES (kms) are miles/kms from first to last pole. There could be more than one circuit on the pole, but it is only counted once. For example, one pole mile of double-hung circuit is equivalent to two circuit miles, but ONE POLE/SPAN mile.

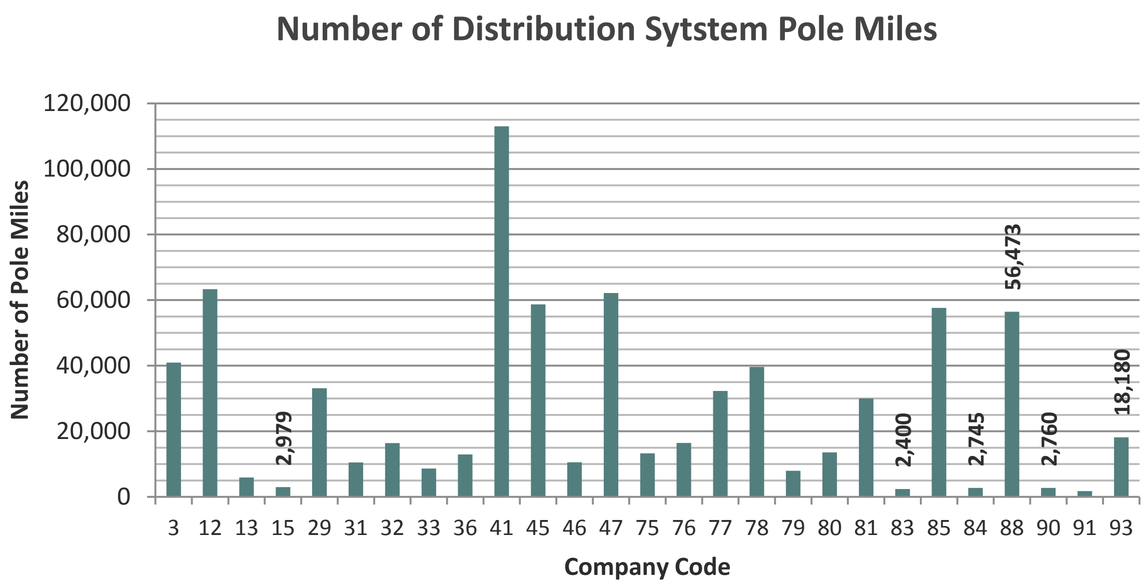

Figure 22: Number of Distribution System Pole Miles

ANNUAL DISTRIBUTION ELECTRIC SALES IN MWH

Question # 33: What is the annual average number of MWh sold and/or delivered by your company's ELECTRIC DISTRIBUTION system?

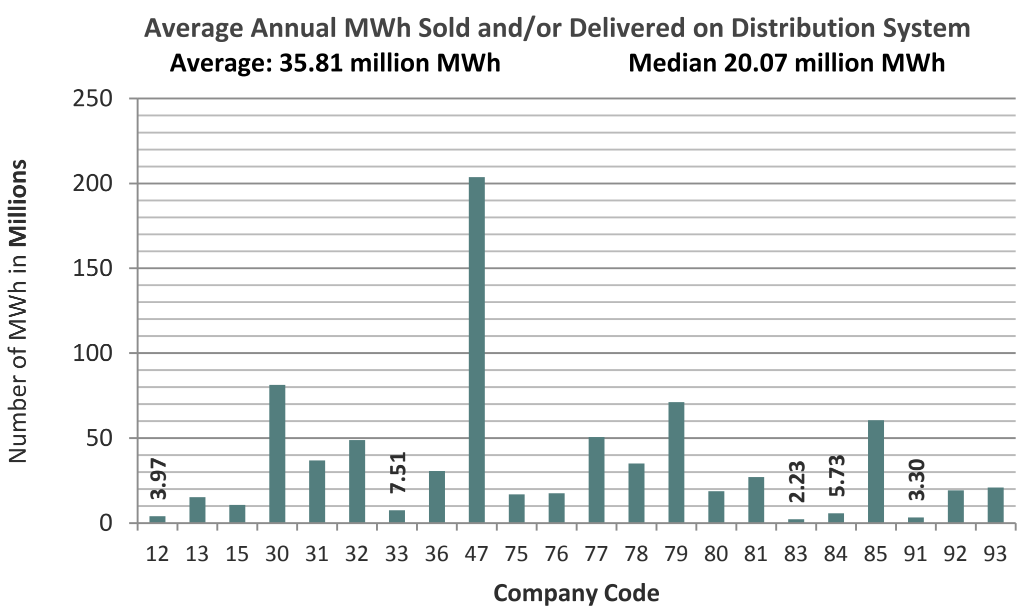

Figure 23: Average Annual MWh Sold and/or Delivered on Distribution System

Discussion of Understanding UVM Workload

There are several variables necessary for understanding UVM workload. Inaccurate information for any of these variables can impact your ability to analyze the efficacy of your program and predict future costs. Understanding UVM workload starts with knowing the dimensions of your electric system and information about the land it is constructed on. Thomas Edison, the founder of electrical distribution systems, said, "*There is no substitute for hard work.*" W. Edward Deming, founder of the *Total Quality Management Movement*, modified this statement to, "*There is no substitute for knowledge.*" This statement emphasizes the need to know more about everything in the system. The following are a few examples where improvements in knowledge of utility distribution systems may improve quality of vegetation management.

- **Pole Miles versus Circuit Miles:** Fewer companies reported pole miles than reported circuit miles. *Pole miles are a more accurate representation of the vegetation management system than circuit miles.*
    1. The companies that reported pole miles also answered the question asking for how many double and triple hung pole miles and their associated voltages. The companies who did not report pole miles also did not report double and triple hung miles, excepting one company. *Knowledge of the electrical system enables knowledge of the vegetation management system.*
    2. Double and triple hung circuits do not represent a large percentage of the pole miles. In previous surveys, 5-10% of their pole miles were reported as multiple hung circuits. *In terms of budget, operations, reliability and quality assurance, 5-10% is significant.*
- **Feeder Lines versus Taps:** The risk, frequency and cost of vegetation management along feeder lines are potentially different than single-phase taps and secondaries. An accurate account of the various voltages and configurations would further inform managers of their workload.
- **Customers Requiring UVM on Their Property**: Another important variable that impacts UVM workload was addressed earlier in the discussion on percent of customers requiring UVM on their property. Recall that a majority (57% of companies) perceive their workload as 100% of their customers, even though chances are that a good percentage of their customers would never require any UVM on their properties. (See Data Discussion on Percent of Customers Requiring UVM on Their Property) *In terms of budget, customer relations and operations, the knowledge of how many customers require direct communication is essential.*
- **Tree Inventories:** Workload assessment, of course, requires knowledge of tree inventory. This data is found later in the report (See Tree Inventories) and only contains about 50% percent of respondents supplying number of trees managed. In the group of companies that supplied tree inventories, many of them were estimates or reports from contractors. *Tree Inventories supply UVM departments with information about tree*

densities and species, which aid in budgetary issues, operations, work schedules and reliability.

Conclusion: Building knowledge of your system is the first step to understanding your workload. The assumptions used to establish budgets, resources and methodology may be limited when important system information is missing.

DISTRIBUTION UVM PROGRAM ORGANIZATION

UTILITY PERSONNEL IN CHARGE OF DISTRIBUTION UVM PROGRAM

Three tables have been built from question #34 (below). Utilities vary tremendously in personnel that manage UVM. This variation may be dependent upon size of utility, size of territory and type of utility. Along with the title of the person in charge of distribution UVM, the average, median and range of the salaries for this position are included at the top of the first table. The second table supplies the name of the manager's department. The third supplies who this person reports to.

Question #34: The objective of this question is to discover the title of the person at your utility who is directly responsible for or has the most control over the distribution vegetation management program, the name of this person's department, who this person reports to, and his yearly salary.

What is the title of the person at your utility who is directly responsible for or has the most control over the distribution vegetation management program? Salary: Average: $123,533.33 Median: $120,000 Range: $90,000 - $180,000
Director Vegetation Management & Ancillary Programs
Vegetation Management Manager
Director Distribution Engineering & Mapping
Director of Vegetation Management
Senior Manager
Manager
Director
Lead Forester
Superintendant, Vegetation Management
Manager, System Forester
C&M [Construction and Management] Manager
PD [Procurement Department] Contract Services Manager
Section Leader
Line Clearance Arborist
Administrator of the Vegetation Management
Manager, T&D System Vegetation

Figure 24: Title of the Person at Utility Directly Responsible for Distribution VM Program and Salary Range

What is the name of this person's department?
Vegetation Management and Ancillary Programs (4 Programs)
Vegetation Management (5 Programs)
Distribution Engineering & Mapping
Project & Program Delivery
Forestry Services
Line Clearance
Distribution Services
Construction & Maintenance
System Maintenance
PD [Procurement Department] Contract Services
Asset Management

Figure 25: Name of UVM "Director's" Department

Who does this person report to? Title of the next level of management above the person in charge of distribution vegetation management
Director Transmission Field Operations (4 Programs)
Director of Distribution Services
Vice President of Engineering
Managing Director - T& D Support Services
VP for Project & Program Delivery
Vice President of Lines and Forestry
Utility Supervisor
Manager, T&D
Director, Technical Services & System Reliability
VP Electric Operations
PD [Procurement Department] Services Manager
System Maintenance Manager
Manager of Forestry and Special Programs
Management of Activities and Processes
Vice President, Asset Management

Figure 26: Who UVM "Director" Reports To

DUTIES OF UVM "DIRECTOR"

In 2002, only **7%** of the participants had Transmission and Distribution UVM separated with different "Directors." By 2006, **13%** of the programs were *Centralized by Program* (one person in charge of distribution and one person in charge of transmission UVM). In 2010 (as seen in the next chart), **25%** of the participants have a dedicated "Director" of distribution UVM. There is a definite (and significant) trend towards this separation in UVM programs, but it is still only in the minority of companies.

Question #35: What are the duties of the person at your utility who is responsible for the distribution vegetation management program?

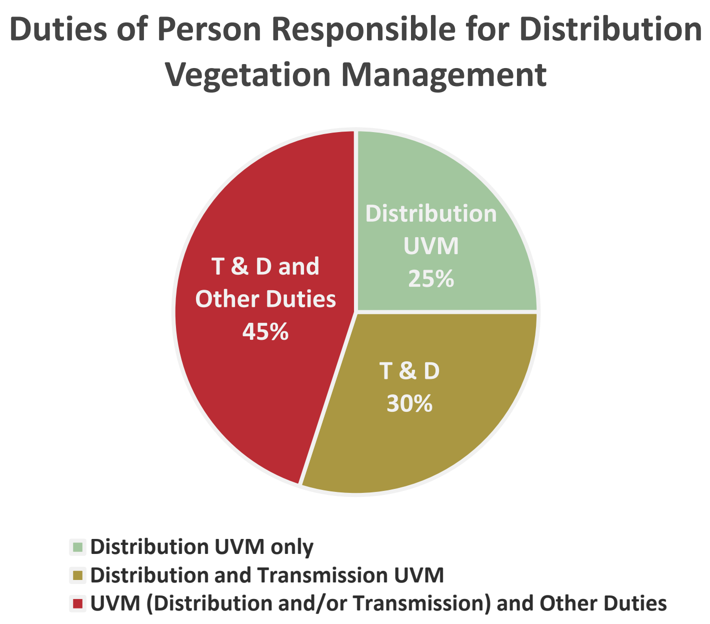

Figure 27: Duties of Person Responsible for Distribution Vegetation Management

"Director's" Other Responsibilities besides Distribution UVM
Wood pole maintenance program (4 programs) [T&D and Other Duties]
Electric engineering, maintenance & mapping [T&D and Other Duties]
Capital Programs where there is a vegetation component [T&D and Other Duties]
Substation Weed Control [T&D and Other Duties]
Construction overhead and underground [Answered Distribution Only]
Wildlife Protection [T&D and Other Duties]
Distribution and Sub-Transmission (46KV) [Answered Distribution Only]

Figure 28: "Director's" Other Responsibilities besides Distribution UVM

Question #36: How many people are performing planning, quality assurance and supervision duties for distribution vegetation management under the direction of the company person most responsible for or who has the most control over distribution vegetation management (person identified in Question #35 or UVM Director)? NOTE: This category does NOT include tree crews.

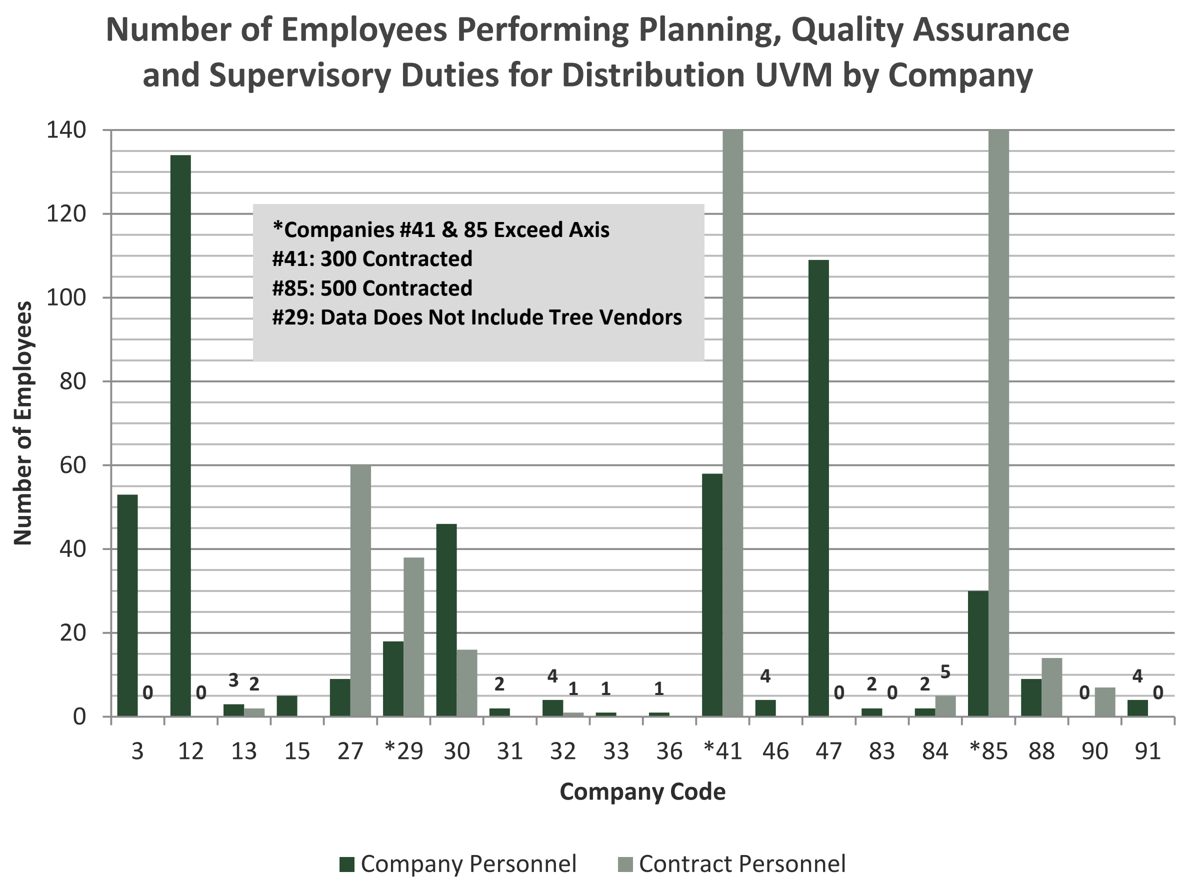

Figure 29: Number of Employees Performing UVM Planning, Quality Assurance and Supervisory Duties

Comments on Personnel Who Perform Planning, Quality Assurance and Supervisory Duties
In house crew supervisors who plan day-to-day work for in house crews and supervise crews are included above.

Figure 30: Comments on Personnel Who Perform UVM Planning, Quality Assurance and Supervisory Duties

Question #37: The objective to this question is to discover how many different MANAGEMENT AND SUPERVISORY positions are in your COMPANY that directly support the vegetation management program and what their duties are. Titles for the positions are not identified, since they vary between companies. Please check the principle responsibilities of each position (check all that apply). UVM Director is the person at your utility who is directly responsible for or has the most control over the distribution vegetation management program. NOTE: It is highly possible that your company is not organized such that Position #2 reports to the UVM Director and Position #3 reports to Position #2. Therefore, we would like you to describe various positions at your company and we will further clarify the chain of command in subsequent questions. We will be asking for the title of each position, who they report to and how many employees hold this position at your utility in the next question.

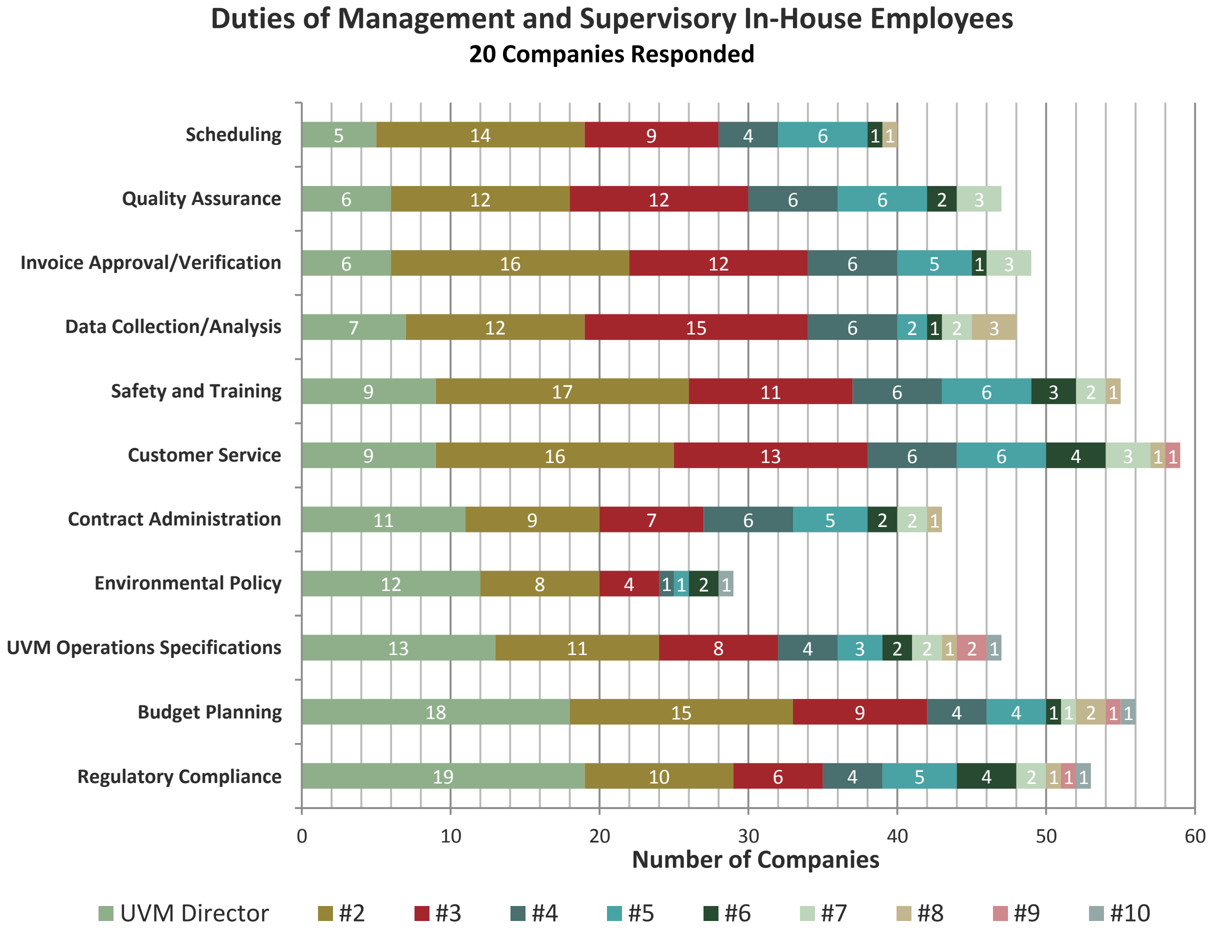

Figure 31: Duties of Management and Supervisory In-House Employees

Data collected from **Question #37**

Since some companies have ten distinct in-house management levels in terms of duties and some only have two levels, it is important to know what percent of companies have 1 – 10 levels of in-house management. The following chart shows the percent of companies that have these different levels. There are 20 companies that answered this question.

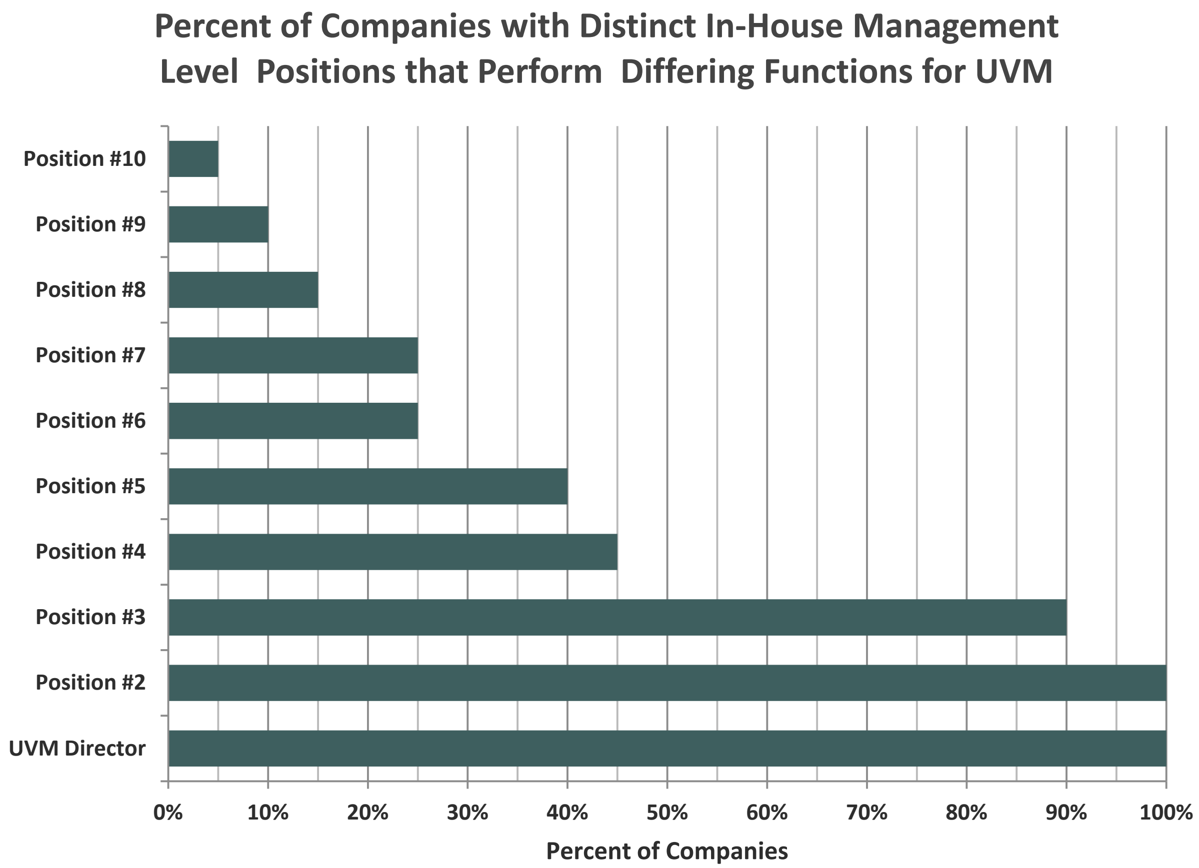

Figure 32: In-House Distinct Management Level Positions that Perform Differing Functions for UVM

Comments on In-House Management Positions
There seems to be a contract management focus in this question which doesn't apply to [our Utility]. Contract administration is comparable to our local leadership groups.
Position #2 is a Division Forester.

Figure 33: Comments on In-House Management Positions

Data collected from **Question #37**

20 Benchmark Participants answered this question. Note: Two categories were not listed for any position at several companies (15 companies listed *Environmental Policy* and 19 companies listed *UVM Operation Specifications* as UVM duties). Most of the eleven duties listed in Figure 30 are performed by more than one position "class" at a majority of utilities. These same duties are listed in the vertical axis of the next ten graphs and illustrate the range of activities as they are spread out over smaller and larger vegetation management departments. There may be more than one employee in each position "class." Bear in mind the company percentages represent position "classes" and not percent per employee.

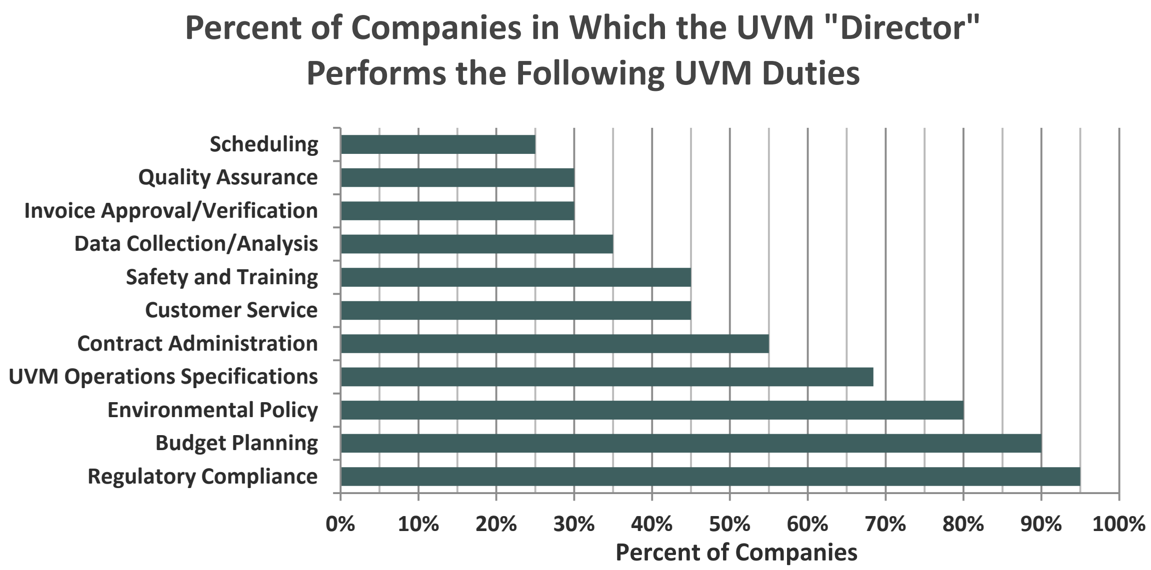

Figure 34: Percent of Companies in Which the UVM "Director" Performs the Following UVM Duties

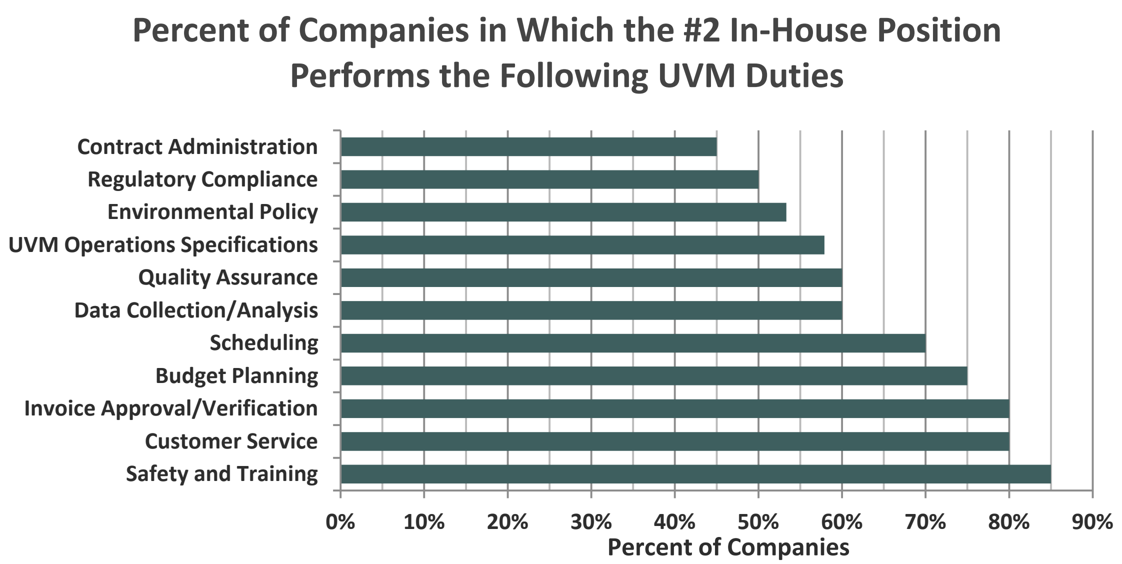

Figure 35: Percent of Companies in Which the #2 In-House Position Performs the Following UVM Duties

Data collected from **Question #37**

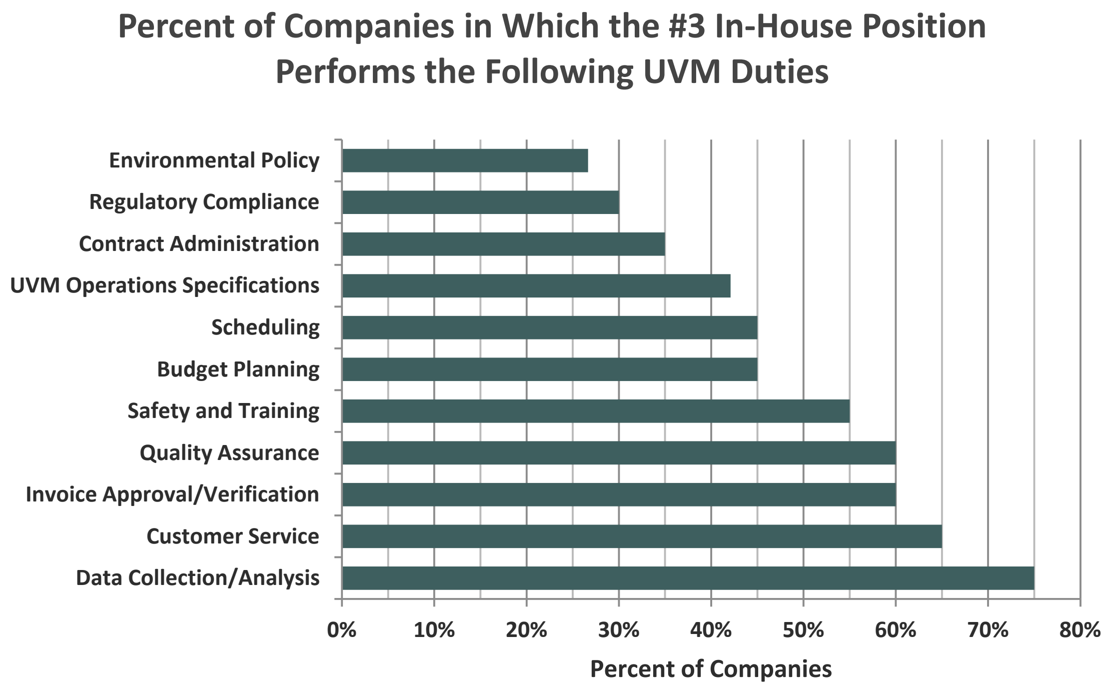

Figure 36: Percent of Companies in Which the #3 In-House Position Performs the Following UVM Duties

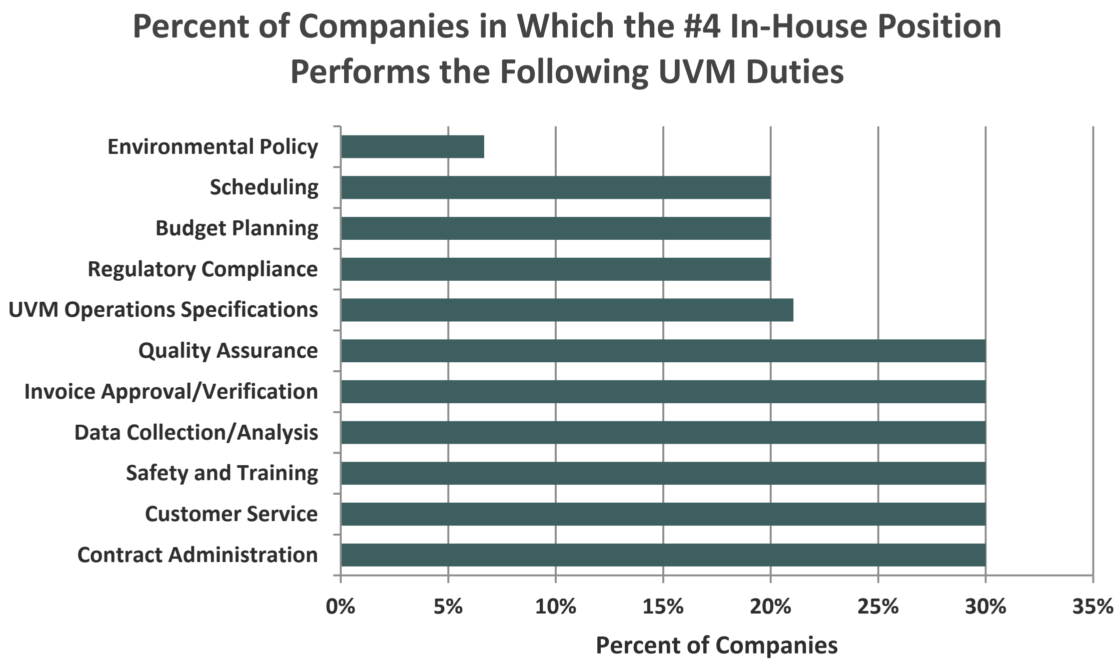

Figure 37: Percent of Companies in Which the #4 In-House Position Performs the Following UVM Duties

Data collected from **Question #37**

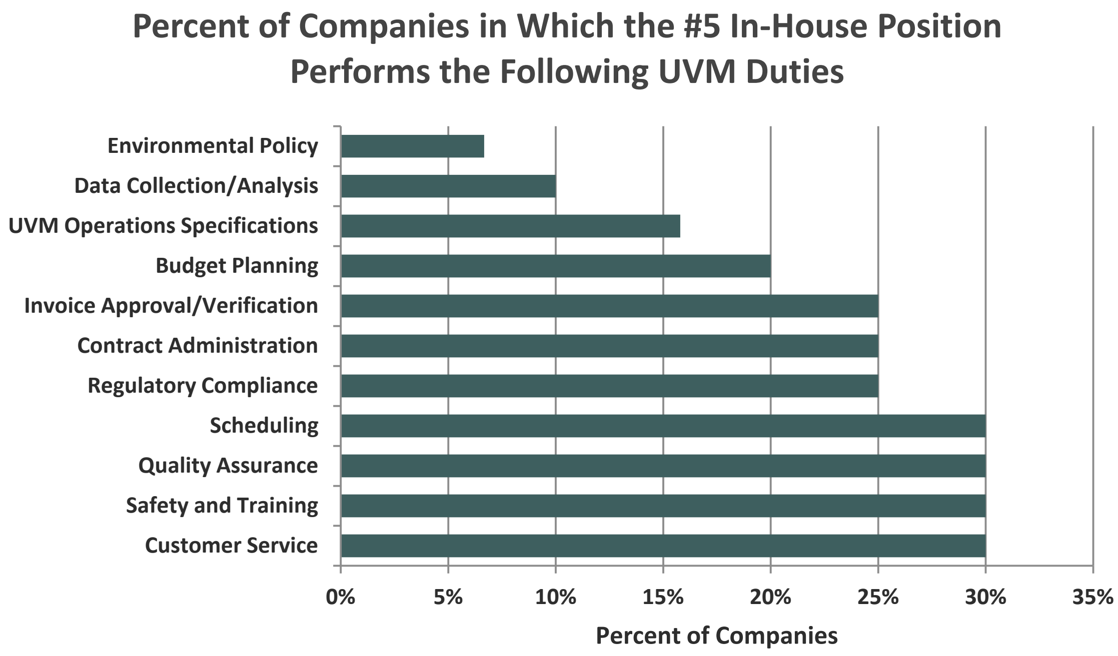

Figure 38: Percent of Companies in Which the #5 In-House Position Performs the Following UVM Duties

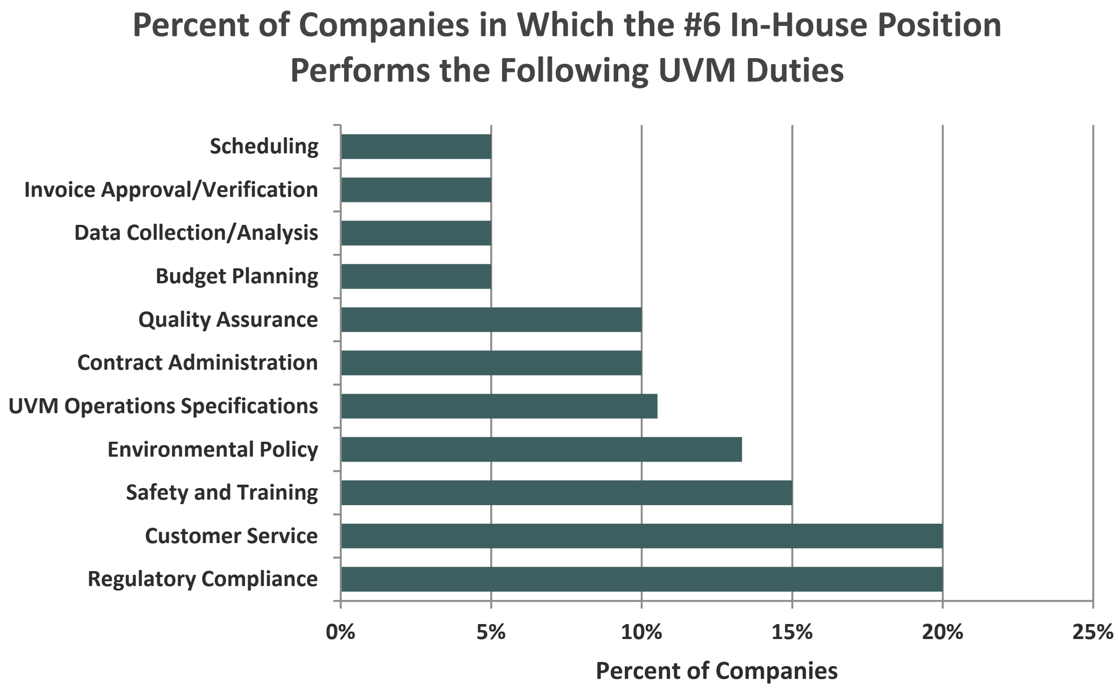

Figure 39: Percent of Companies in Which the #6 In-House Position Performs the Following UVM Duties

Data collected from **Question #37**

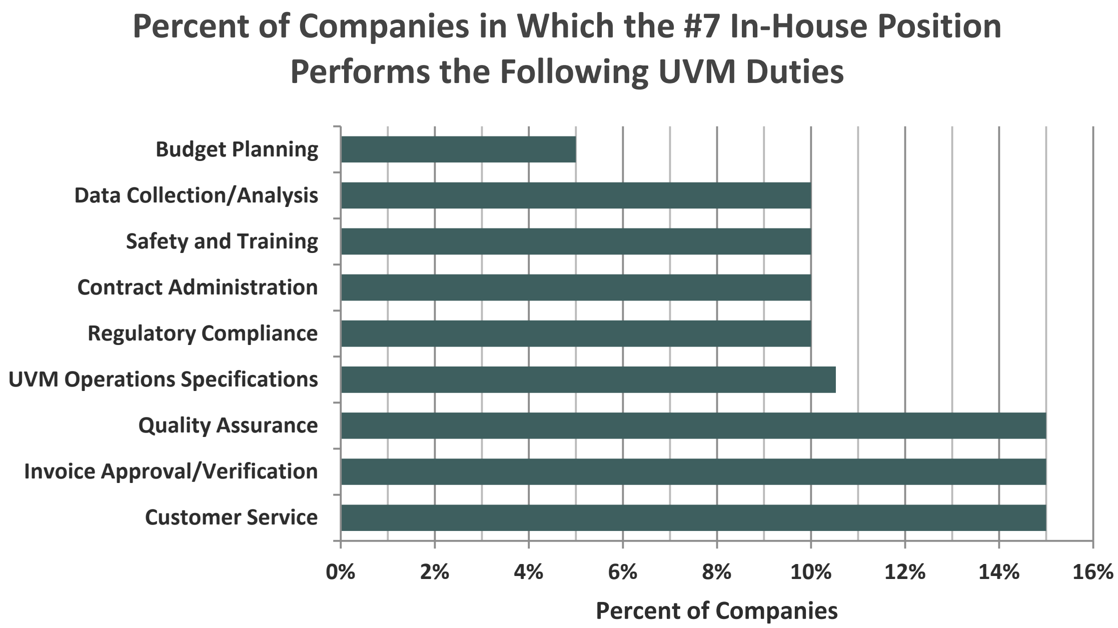

Figure 40: Percent of Companies in Which the #7 In-House Position Performs the Following UVM Duties

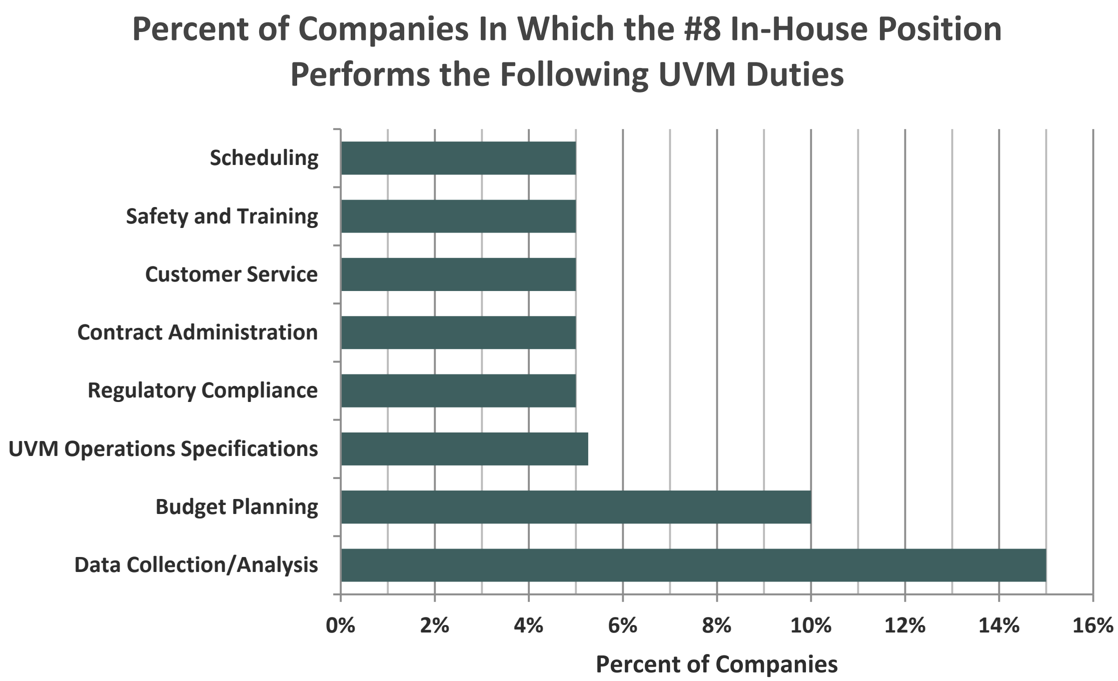

Figure 41: Percent of Companies in Which the #8 In-House Position Performs the Following UVM Duties

Data collected from **Question #37**

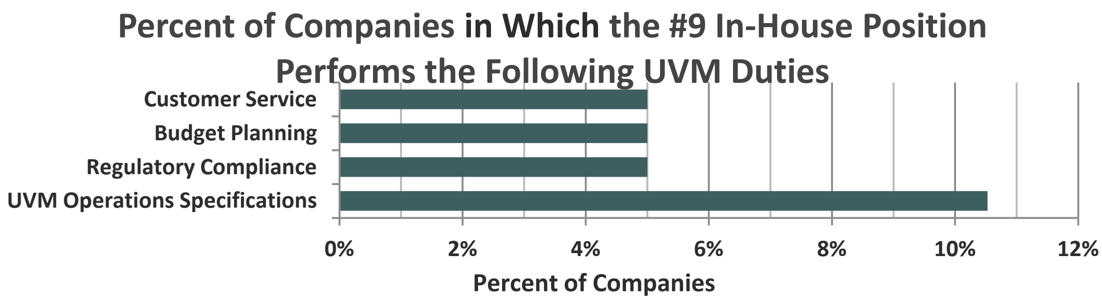

Figure 42: Percent of Companies in Which the #9 In-House Position Performs the Following UVM Duties

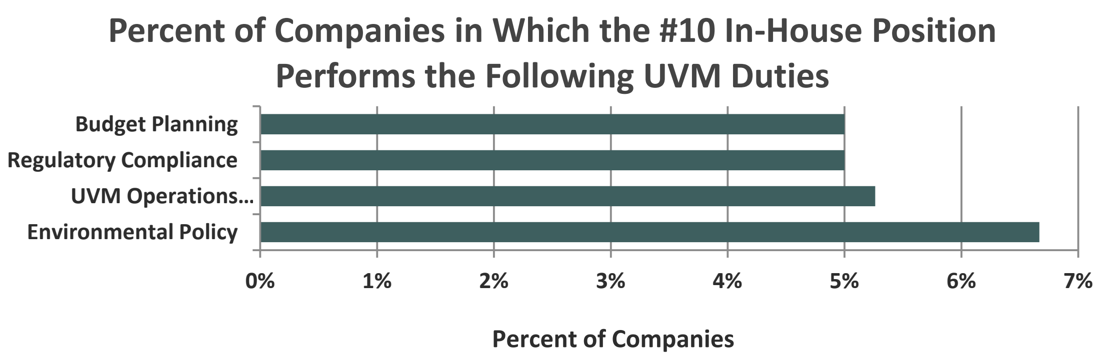

Figure 43: Percent of Companies in Which the #10 In-House Position Performs the Following UVM Duties

Data Discussion of Management and In-House Personnel Duties

While all eleven activities were responded to by most companies, it is apparent that some activities are more likely to be performed by the "Director" of UVM whereas other duties are relegated to other positions.

1. The preceding analysis can be used as an indicator of how to assign duties when building a new or reconstructing an existing UVM program.
2. **UVM "Director Activities:** *Regulatory Compliance* and *Budget Planning* are activities that universally performed by the UVM "Director." A study of the data shows that the UVM "Director" in a majority of companies is engaged in fewer of the listed activities than all the other positions. *This emphasizes the importance of compliance and budgets to the director and the UVM program.*
3. **Number of UVM Management Positions:** The responses show that all companies have at least two management position "classes" in the UVM department. A minority of companies have more than three management positions.

IN-HOUSE VERSUS CONTRACT EMPLOYEES

Question #41: The objective of this question is to characterize the personnel who manage the crews that perform line-clearance. You will be asked to supply the number of company and/or contract personnel in each position.

General Forepersons

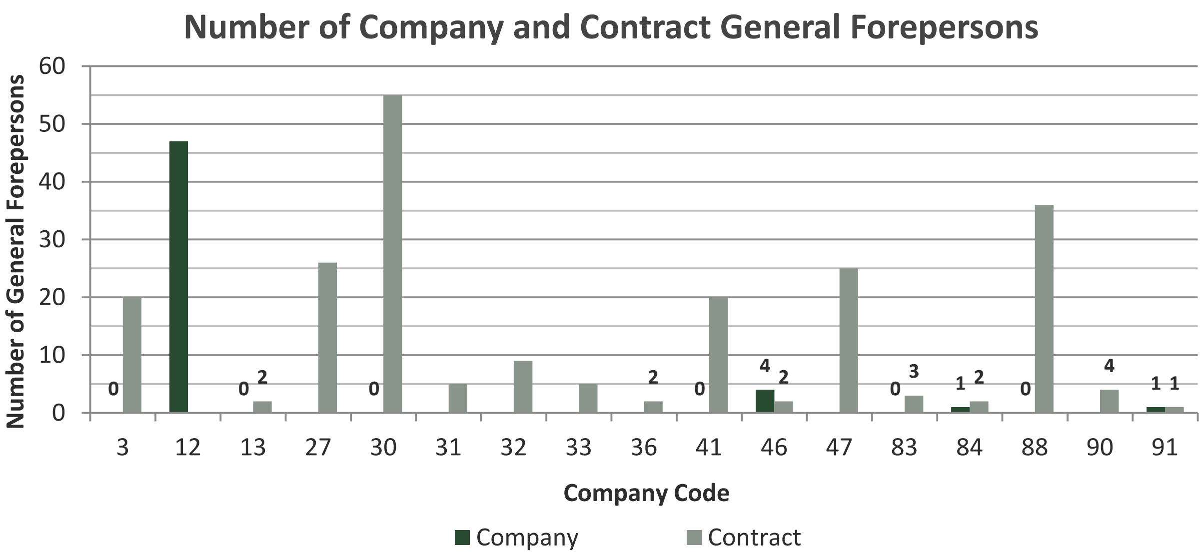

Figure 44: Number of Company and Contract General Forepersons

The following chart was created using calculated statistics from data derived from question #41.

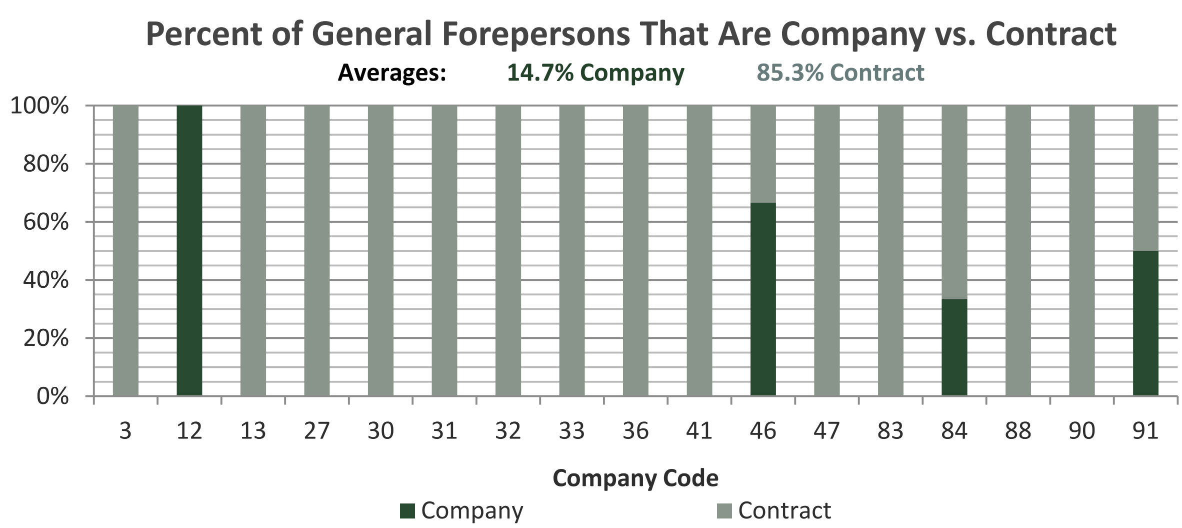

Figure 45: Percent of General Forepersons That Are Company vs. Contract

Crew Leaders

Data collected from **Question #41**

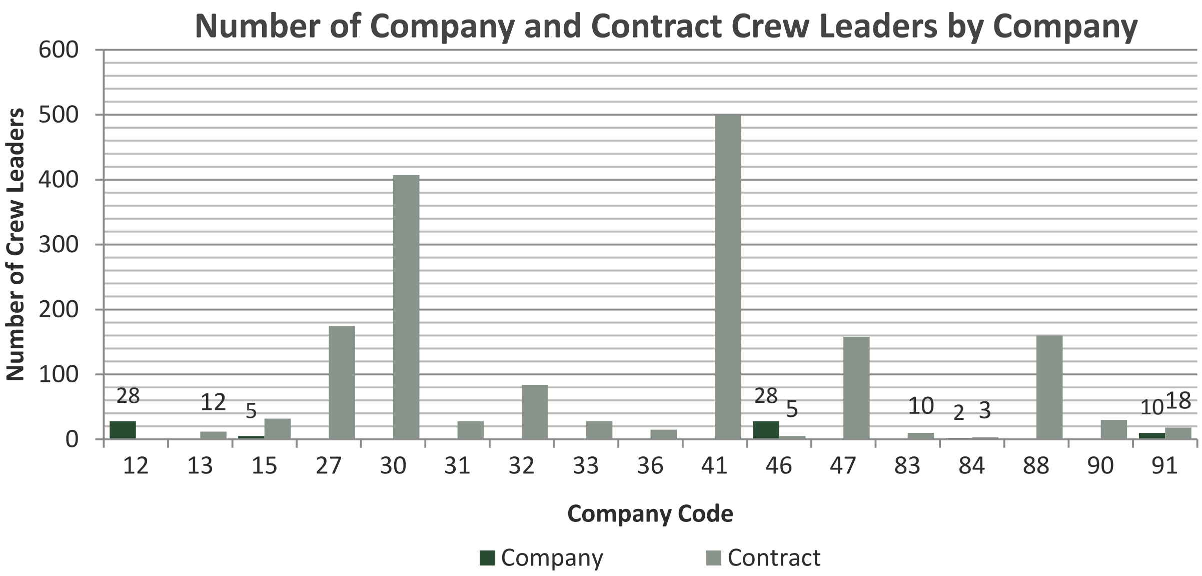

Figure 46: Number of Company and Contract Crew Leaders

The following chart was created using calculated statistics from data derived from question #41.

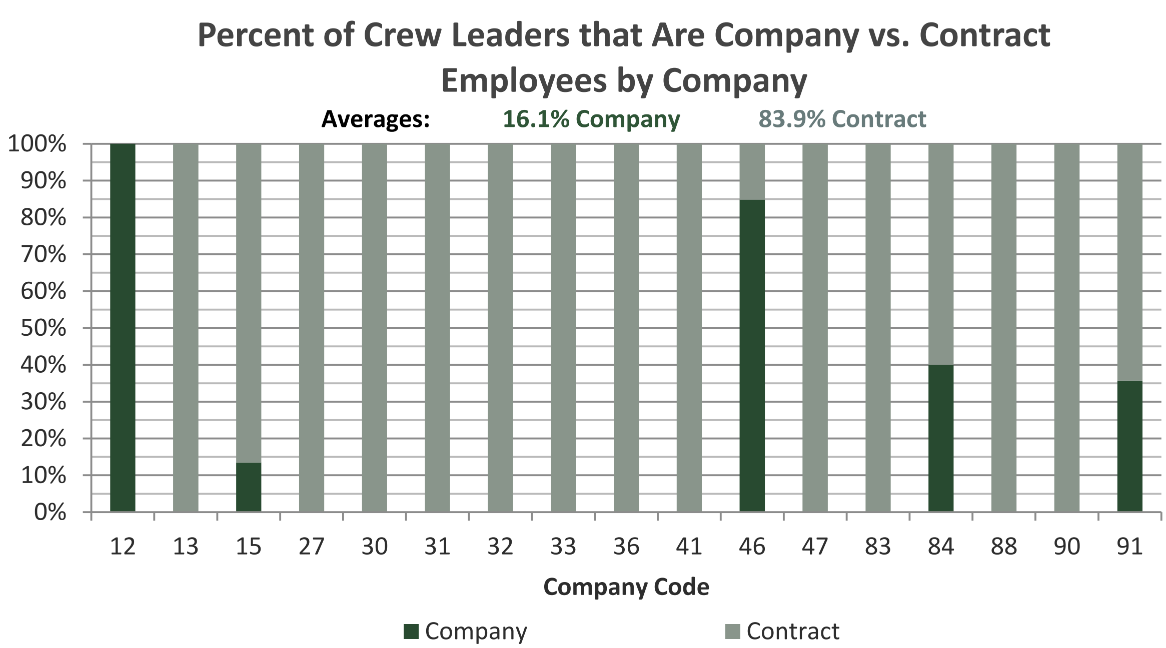

Figure 47: Percent of Crew Leaders That Are Company vs. Contract Employees

Qualified Line-Clearing Arborists

Data collected from **Question #41**

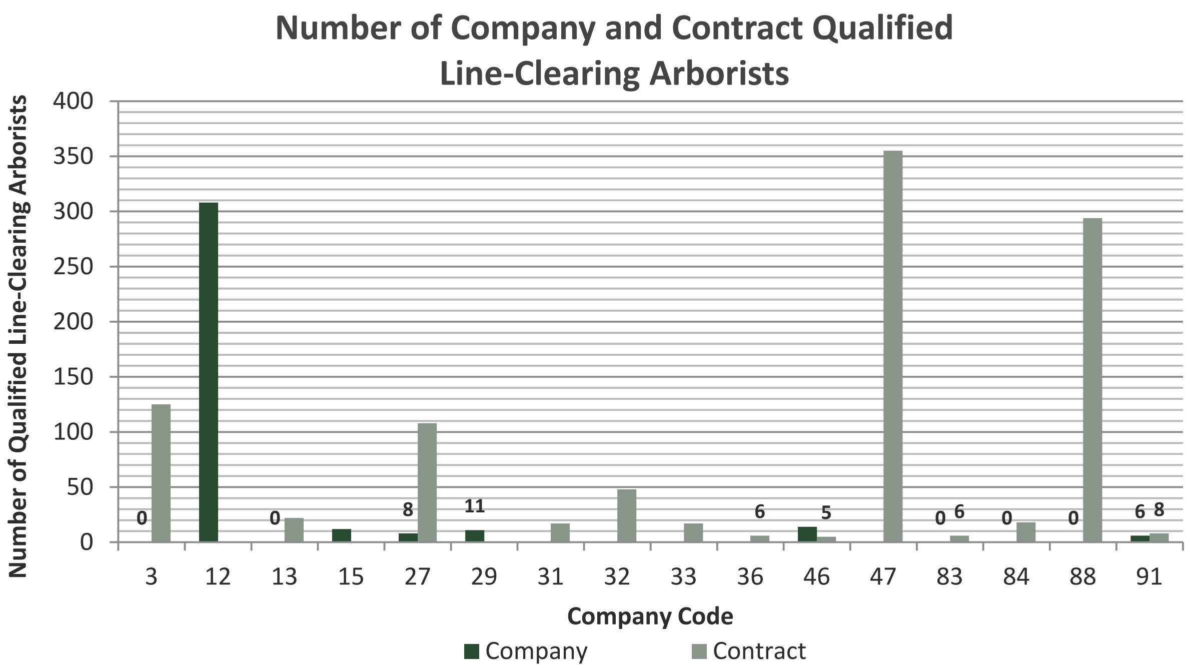

Figure 48: Number of Company and Contract Qualified Line-Clearing Arborists

The following chart was created using calculated statistics from data derived from question #41.

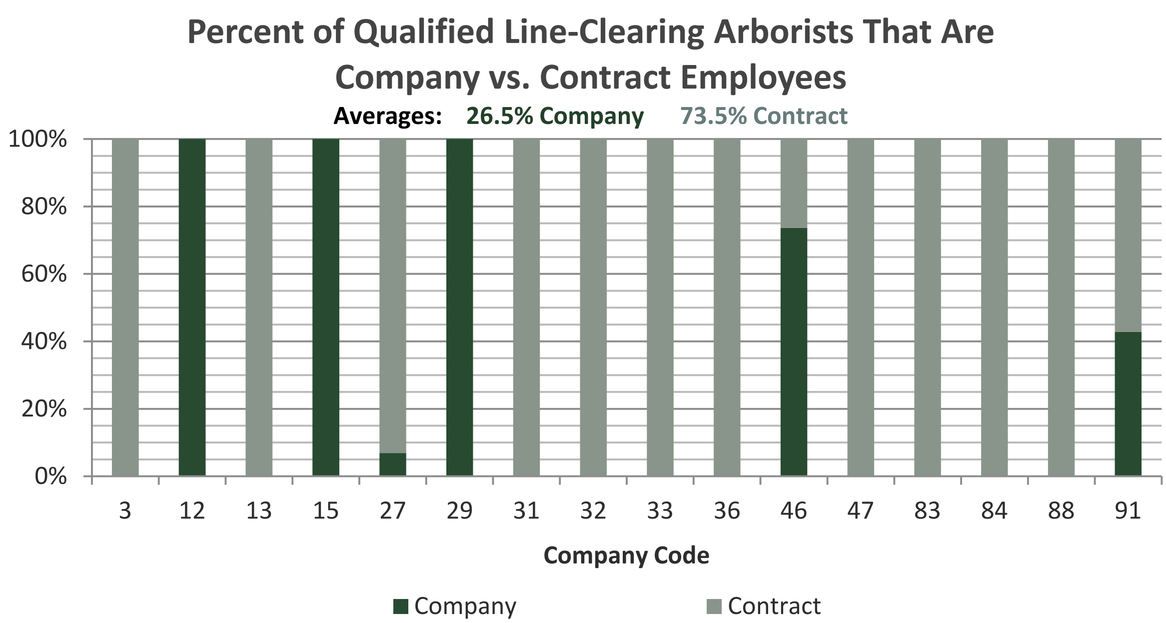

Figure 49: Percent of Qualified Line-Clearing Arborists That Are Company vs. Contract

Qualified Line-Clearing Arborist Trainees

Data collected from **Question #41**

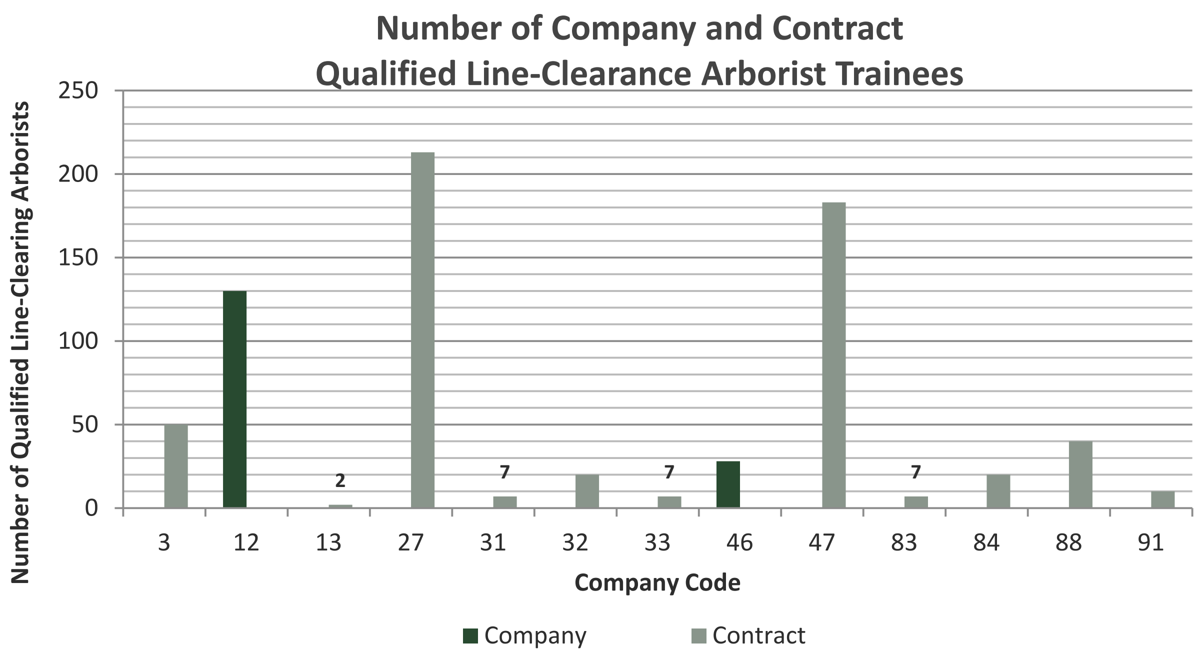

Figure 50: Number of Company and Contract Qualified Line-Clearance Arborist Trainees

The following chart was created using calculated statistics from data derived from question #41.

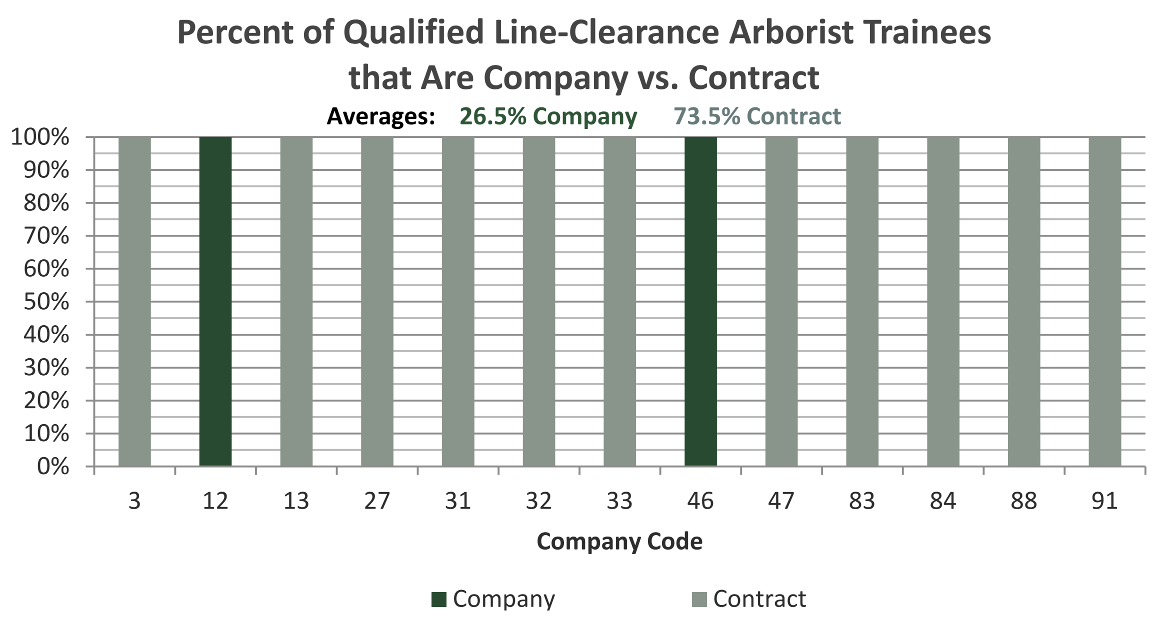

Figure 51: Percent of Qualified Line-Clearance Arborist Trainees That Are Company vs. Contract

DISTRIBUTION PROGRAM CHANGES

Changes in Job Titles and Descriptions for UVM Personnel

Question #43: In the last five years, have you changed the title and job descriptions of the company personnel in your distribution UVM department?

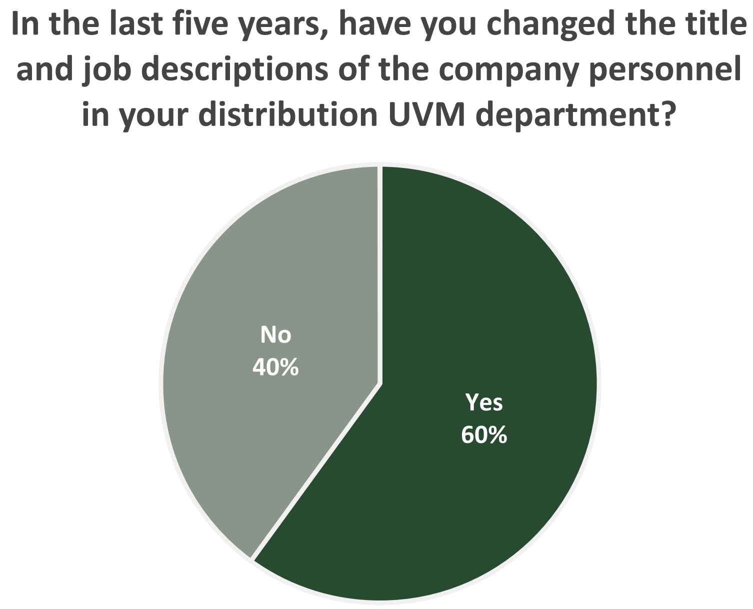

Figure 52: Changes in Job Titles and Descriptions for UVM Personnel

Comments on Changes in Job Titles and Descriptions for UVM Personnel
Field Coordinator title changed to Supervisor
Regional Foresters to Program Manager - Forester System wide & manage programs
System Forester is now Director of Vegetation Management. Foresters are now either Supervisors - Veg Mgmt or Arborist (Utility Forestry) depending on level of education.
Geographic and role alignment changed to clarify roles and focus responsibility.
Reworded job title and description to comply with regulations. MORE THAN ONCE!
Updated Supervisor position descriptions.
Updated descriptions and added title - Senior Forester.
Changed title of general foreman to job planner, because they are solely in charge of getting permission from land owners.
Our Company integrated Transmission & Distribution Vegetation last year. With this change some job titles and job descriptions were adjusted.

Figure 53: Comments on Changes in Job Titles and Descriptions for UVM Personnel

Changes in Utility Vegetation Management Programs

Question #44: In the last five years, have you rewritten or significantly revised your distribution UVM program?

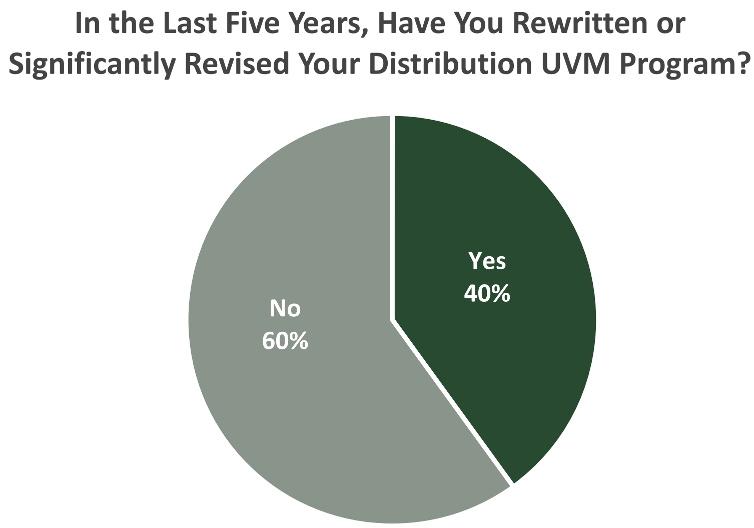

Figure 54: Changes in Distribution Program in Last Five Years: Yes or No

Comments on and Explanations of Changes in Distribution UVM in the Last Five Years
Changed from 10'4" to 7' on primary voltage pruning   Tracking all reactive & restoration   Change from [contractor 1] to [contractor 2] as primary (alliance) contractor. Added T&D Managers.
Moved from general specification to Site Specific prescriptive program based on cycle length. It is also managed in a GIS based computer program.
Rewritten to ensure compliance of NERC lines and Non NERC lines so that there is less confusion.
Significant changes in budget have caused program to be altered from proactive to strictly reactive.
We now trim by sub and circuit. We have identified our sub and circuits per customer density for scheduling purposes. Job planner(s) obtain permission for row work. Changed our herbicide treatment cycle from 3 to 4 years and expanded treatment area.
We asked the energy board regulator for a special budget for a cycle recovery.
We updated our Program Manual in 2007. Each year a few additional updates are added but these aren't as significant as our 2007 revision.
Defined line clearance specifications.

Figure 55: Comments on and Explanations of Changes to Distribution UVM in the Last Five Years

ANNUAL IN-HOUSE UVM DISTRIBUTION SYSTEM EXPENDITURES

Analysis in Progress: Many companies are still entering data and this analysis will appear in subsequent reports.

ANNUAL CONTRACTED UVM DISTRIBUTION SYSTEM EXPENDITURES

Analysis in Progress: Many companies are still entering data.

TOTAL EXPENDITURES FOR CONTRACTED DISTRIBUTION UVM SERVICES

Companies that spend with greater than $10 million annually have been represented separately from the companies that spend under $10 million annually.

Question #90: ENTER THE TOTAL COST, CONTRACTED LABOR HOURS, AND WORKED POLE/SPAN MILES FOR CONTRACTED DISTRIBUTION UVM SERVICES: This amount should be the total of all the questions asked under contract expenditures, **EXCLUDING storm work and new construction clearing.** For the annual mileage, please supply the POLE/SPAN miles or kilometers worked for ROUTINE MAINTENANCE, only.

Total Annual Costs for Contracted Services over $10 Million

Data Collected from **Question #90** above.

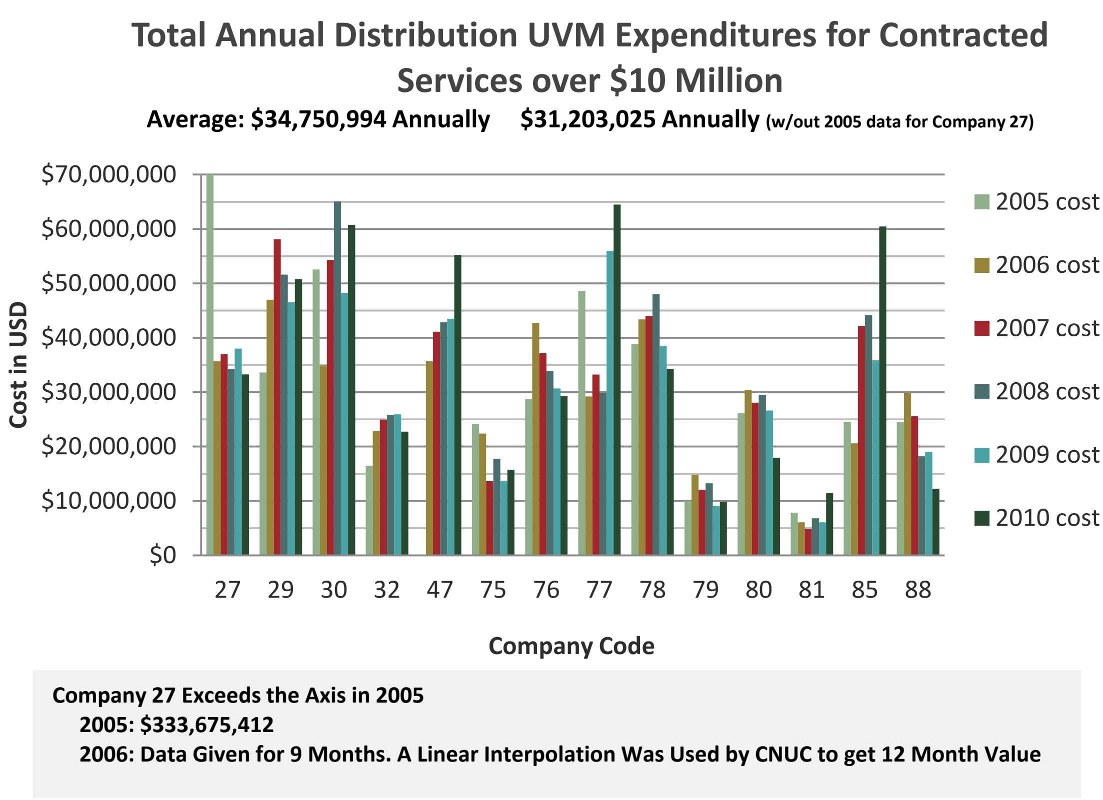

Figure 56: Total Annual Distribution UVM Expenditures for Contracted Services over $10 Million

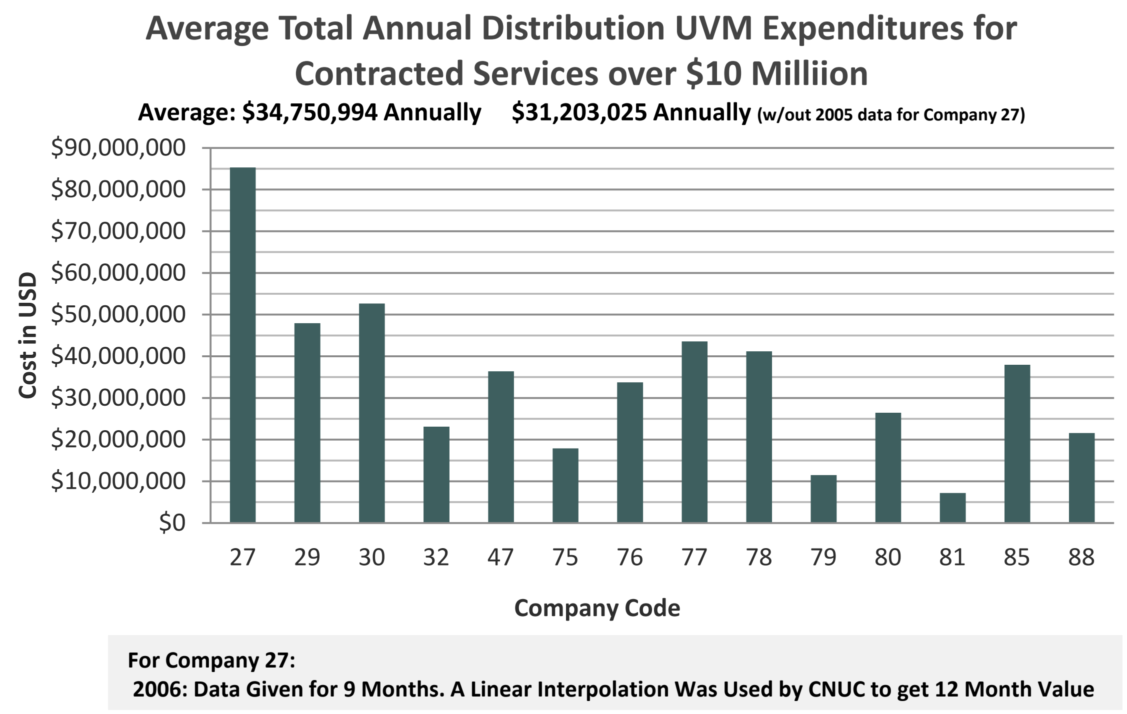

Figure 57: Average Total Annual Distribution UVM Expenditures for Contracted Services over $10 Million

Total Annual Costs for Contracted Services under $10 Million

Data collected from **Question #90**

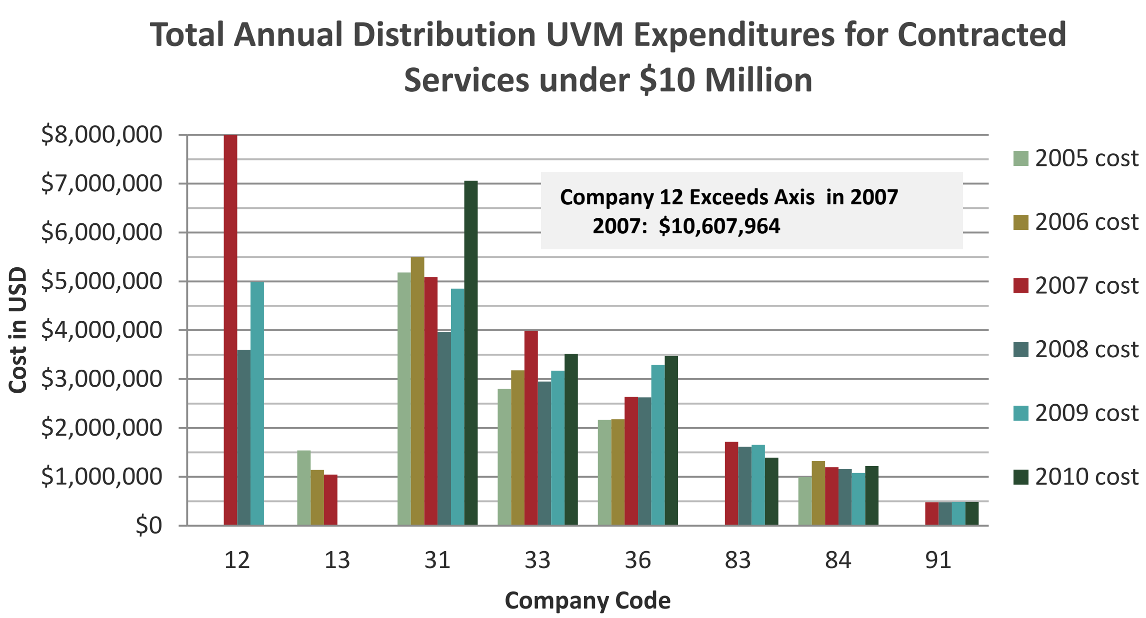

Figure 58: Total Annual Distribution UVM Expenditures for Contracted Services under $10 Million

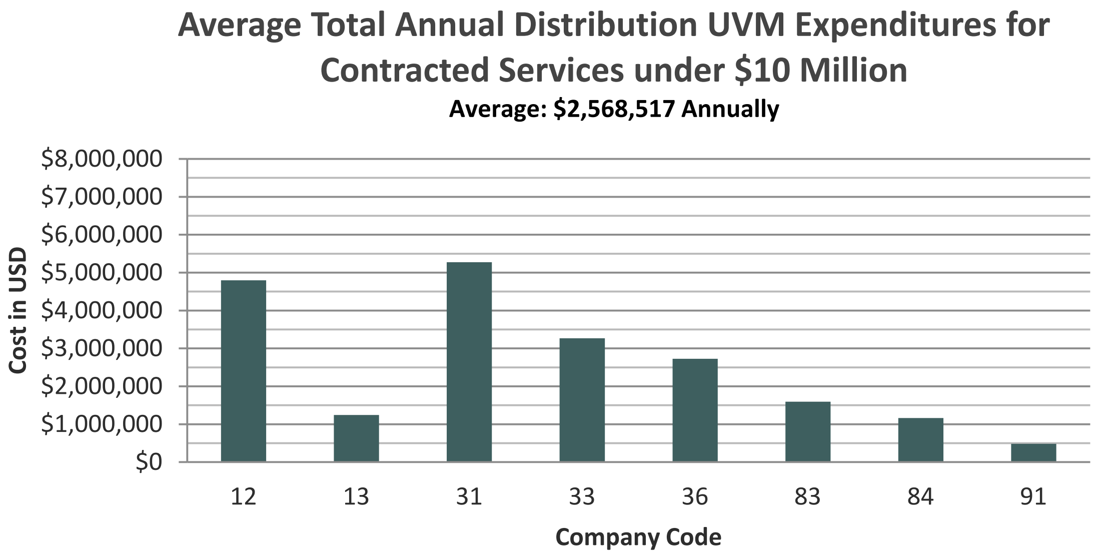

Figure 59: Average Total Annual Distribution UVM Expenditures for Contracted Services under $10 Million

Average Cost per Labor Hour for Distribution Contracted Services

Data collected from responses to **Question #90**. This is a calculated statistic from reported labor hours and reported expenditures for Distribution UVM contracted services.

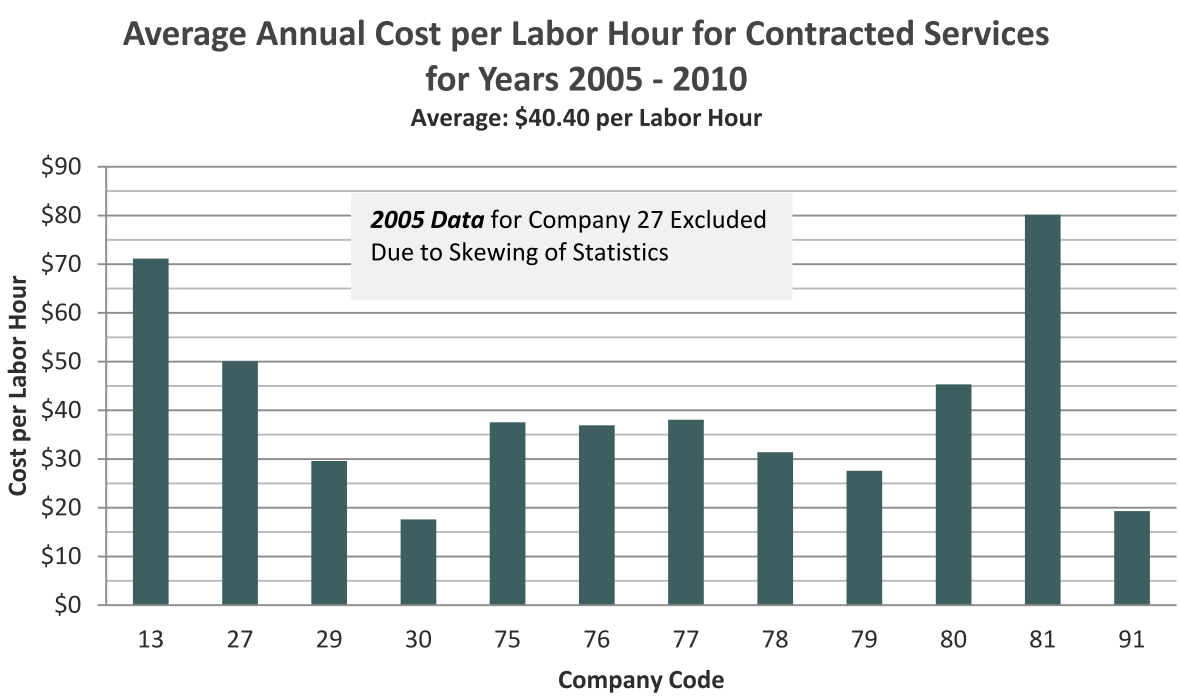

Figure 60: Average Annual Cost per Labor Hour for Contracted Services (2005 -2010)

Average Cost for Contracted Services per Managed Distribution Pole Mile

Data collected from responses to **Question #90**. This is a calculated statistic from reported labor hours and reported expenditures for Distribution UVM contracted services.

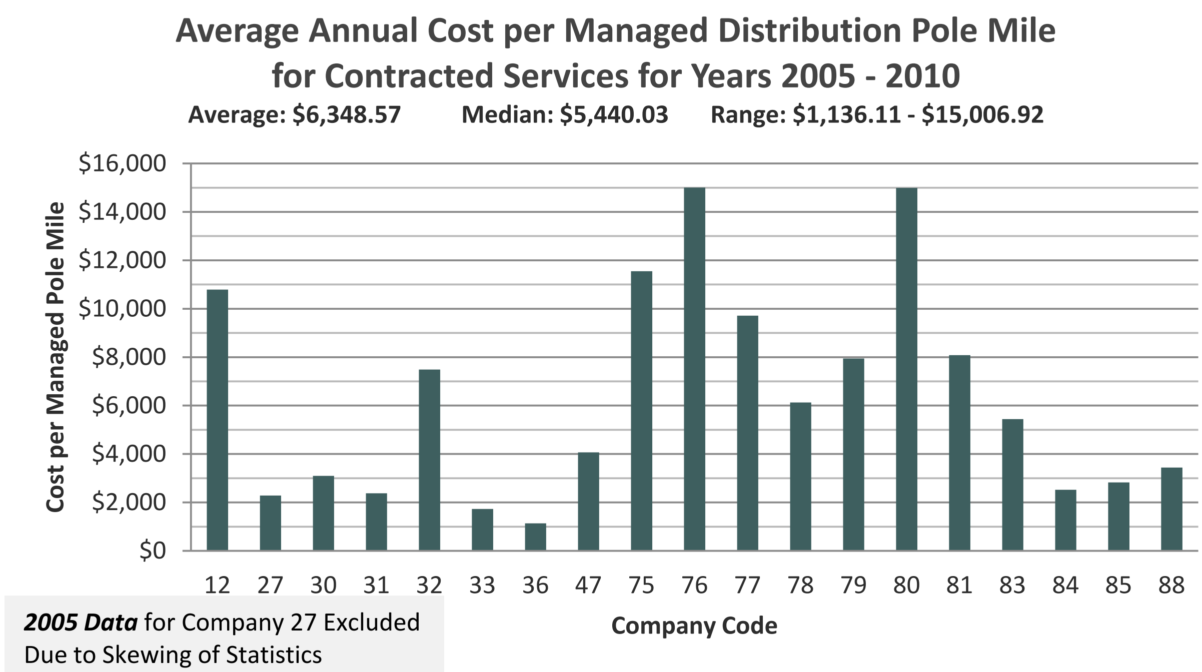

Figure 61: Average Annual Cost per Managed Distribution Pole Mile for Contracted Services (2005 – 2010)

COMMENTS ON CONTRACTED DISTRIBUTION UVM EXPENDITURES

Comments on Contracted Distribution UVM Expenditures
For [Utility], distribution expenditures for interventions following a customer request (phone or internet) are very important; 4 to 6 millions in recent years!

Figure 62: Comments on Contracted Distribution UVM Expenditures

ANNUAL EXPENDITURES FOR STORM RESPONSE, NEW CONSTRUCTION CLEARING AND REACTIVE UVM WORK

TOTAL ANNUAL DISTRIBUTION UVM EXPENDITURES

Question #96: TOTAL ANNUAL EXPENDITURES FOR DISTRIBUTION UVM FROM 2005 - 2010: Please supply the Total Expenditures for Distribution Utility Vegetation Management for the following years. NOTE: Include ALL known costs for vegetation management.

Companies that spend with greater than $10 million annually have been represented separately from the companies that spend under $10 million annually.

Total Annual Costs for Companies with UVM Budgets More Than $10 Million

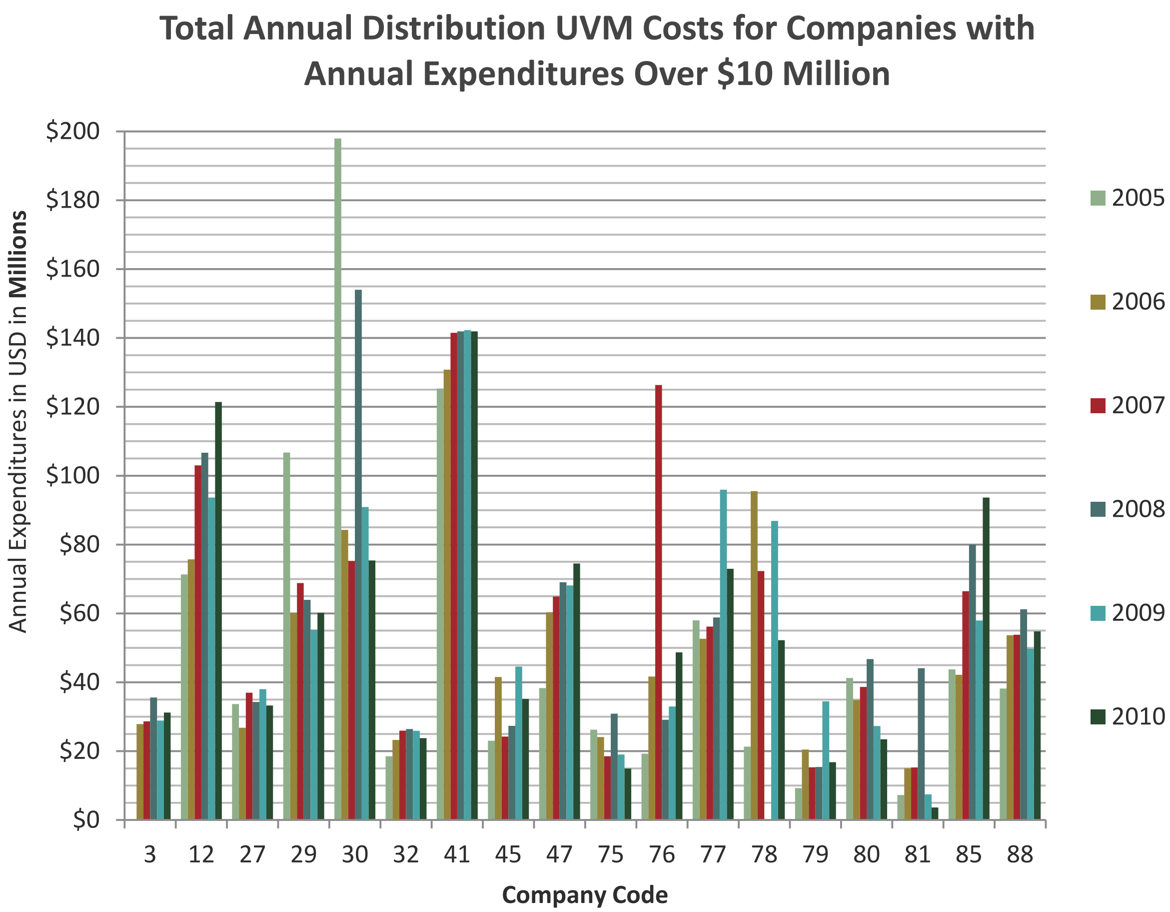

Figure 63: Total Annual UVM Costs for Companies with Annual Expenditures Over $10 Million

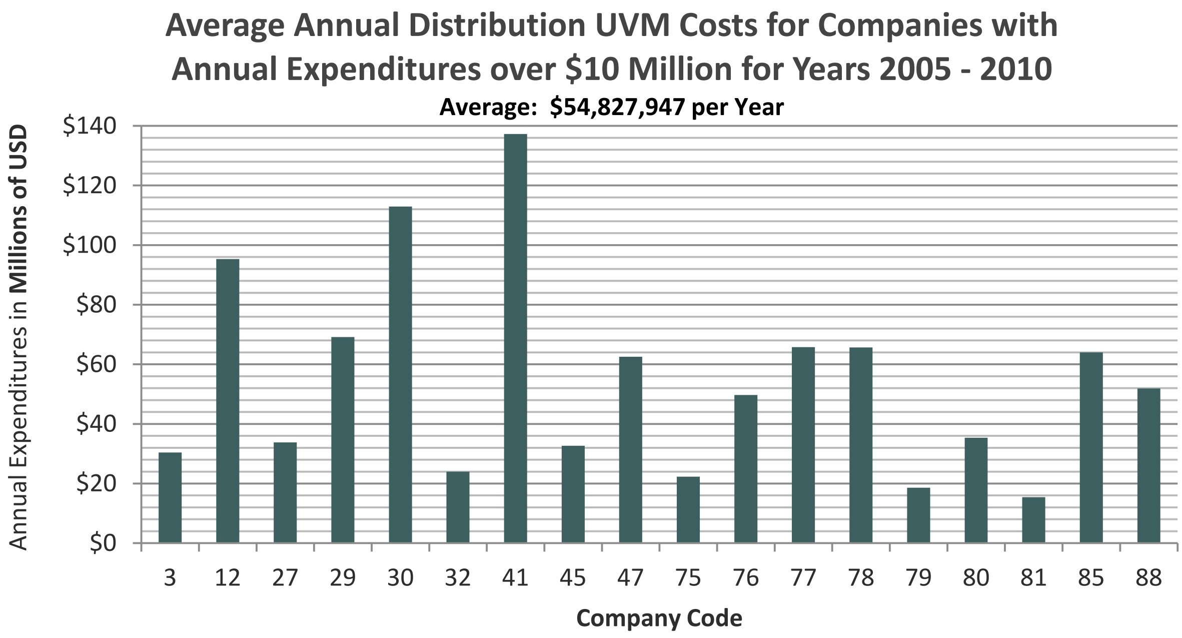

Figure 64: Average Annual UVM Costs for Companies with Costs over $10 Million for Years 2005 - 2010

Total Annual Costs for Companies with UVM Budgets Less Than $10 Million

Data collected from responses to **Question #96**

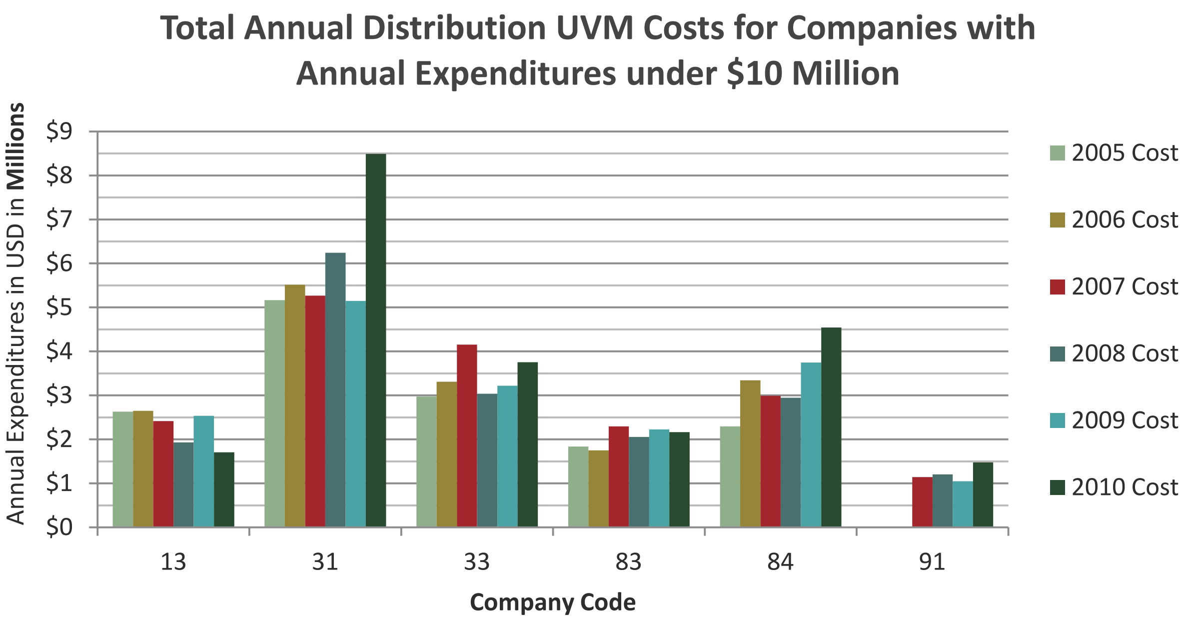

Figure 65: Total Annual UVM Costs for Companies with Annual Expenditures under $10 Million

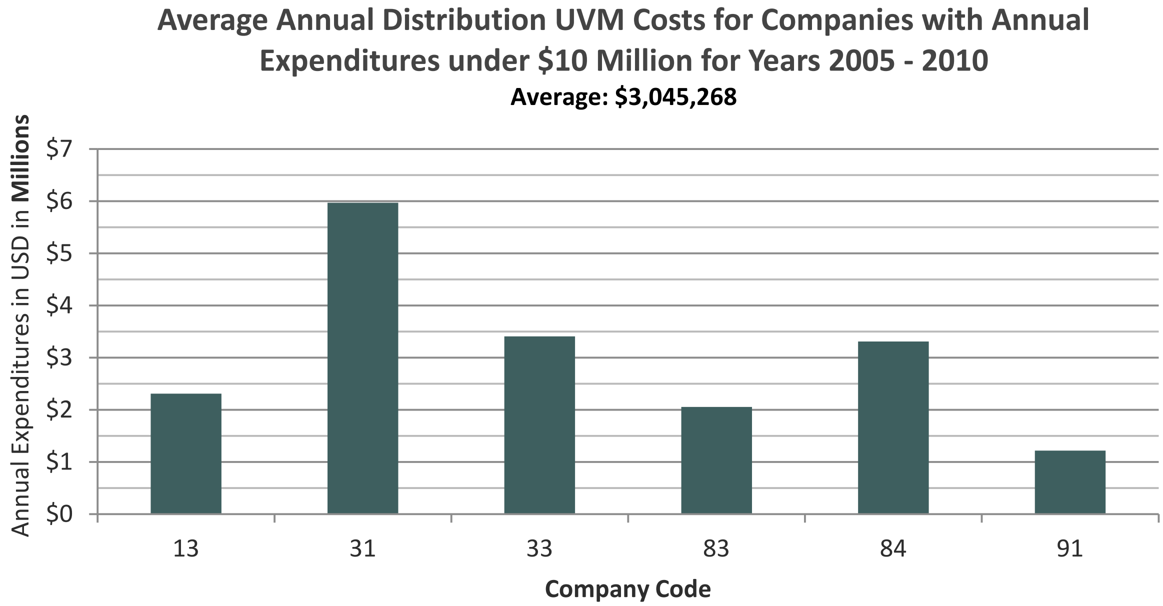

Figure 66: Average Annual UVM Costs for Companies with Costs under $10 Million for Years 2005 – 2010

SPECIAL TREE PROGRAMS: ROUTINE MAINTENANCE OR UNPLANNED

Question #98: ROUTINE MAINTENANCE VERSUS UNPLANNED WORK: This question is to help us understand what aspects of your distribution vegetation management program are considered routine and what are considered unplanned. NOTE: Please give one answer per row.

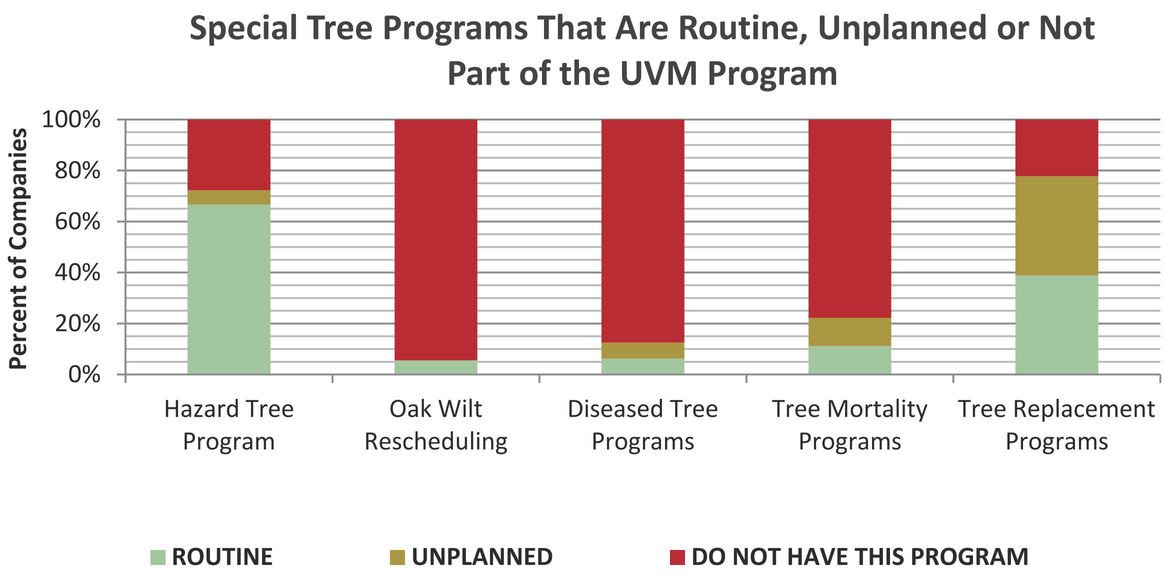

Figure 67: Special Tree Programs That Are Routine, Unplanned or Not Part of the UVM Program

Details from above graph are displayed on the table below:

PERCENT OF COMPANIES WITH SPECIAL TREE PROGRAMS THAT ARE ROUTINE, UNPLANNED OR NOT PART OF THE UVM PROGRAM

Work Scheduling	Hazard Tree Program	Oak Wilt Rescheduling	Diseased Tree Programs	Tree Mortality Programs	Tree Replacement Programs
Routine	67%	6%	6%	11%	39%
Unplanned	6%	0%	6%	11%	39%
Do Not Have This Program	28%	94%	88%	78%	22%

Figure 68: Table of Special Tree Programs That Are Routine, Unplanned or Not Part of the UVM Program

Comments and Descriptions of Special UVM Tree Programs
Maps with concentrations of oaks are scheduled for work outside the oak wilt season.
Annual Dead Tree Program in eastern service area.
Mountain Pine Beetle Program to deal with the MPB infestation
Palm Maintenance Program - Routine Vine Treatment Program - Routine Removal Program – Routine [Other Special Tree Program]
Hazard trees are identified and removed as a part of our routine vegetation management programs. Our tree replacement program is used as a negotiation tool with our customers during the notification/permissioning of our routine vegetation management programs.
Tree Line USA
Tree replacements are offered to landowners where tree removals are necessary.
Hazard Tree Program does include some dead or diseased tree. But the final decision is always based on risk for the system.

Figure 69: Comments and Descriptions of Special UVM Tree Programs

ROUTINE MAINTENANCE EXPENDITURES AND LABOR HOURS

Question #101: Distribution ROUTINE MAINTENANCE EXPENDITURES: This pertains to any UVM that is planned into the budget and performed on a regular basis to keep the distribution lines clear of vegetation. This does NOT include storm, clearing for new construction or unplanned work. Please enter the annual costs and labor hours expended for ROUTINE MAINTENANCE in the following years.

Distribution Routine Maintenance Expenditures

Companies that spend greater than $10 million annually have been represented separately from the companies that spend under $10 million annually.

Annual Routine Maintenance Expenditures for Utilities with Costs Greater Than $10 Million

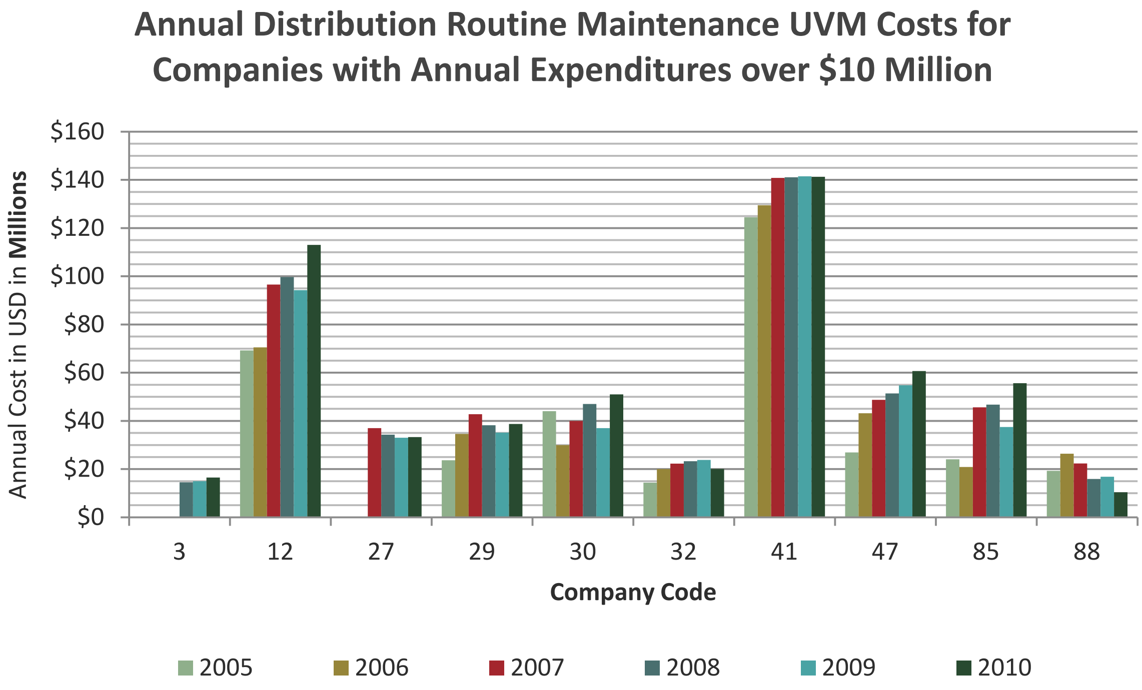

Figure 70: Annual Routine Maintenance UVM Costs for Companies with Annual Expenditures over $10 Million

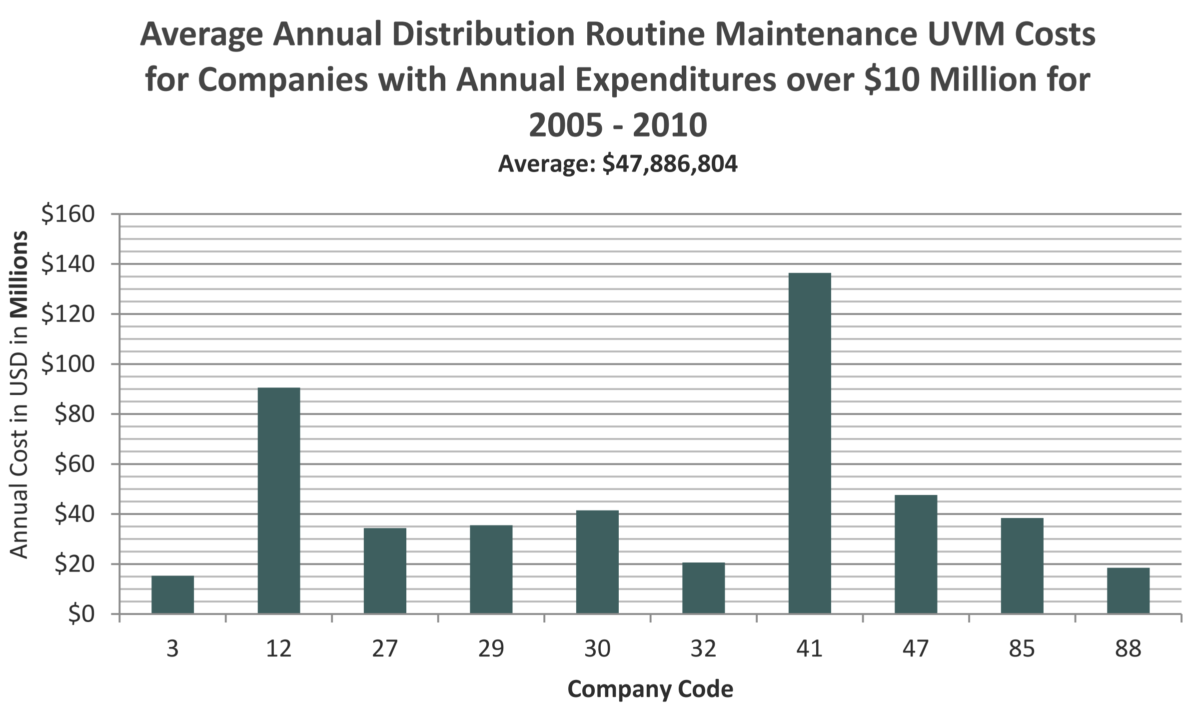

Figure 71: Average Annual Routine Maintenance Costs for Companies with Annual Expenditures over $10 Million

Annual Routine Maintenance Expenditures for Utilities with Costs Less Than $10 Million

Data collected from responses to **Question #101**

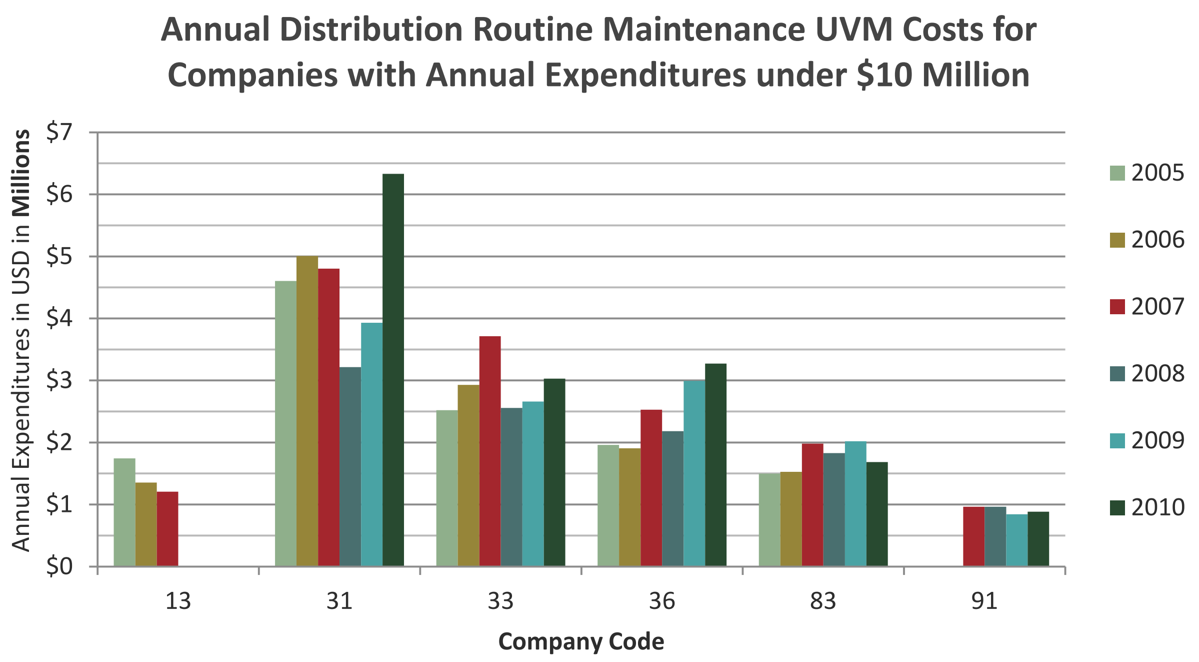

Figure 72: Annual Routine Maintenance UVM Costs for Companies with Annual Expenditures under $10 Million

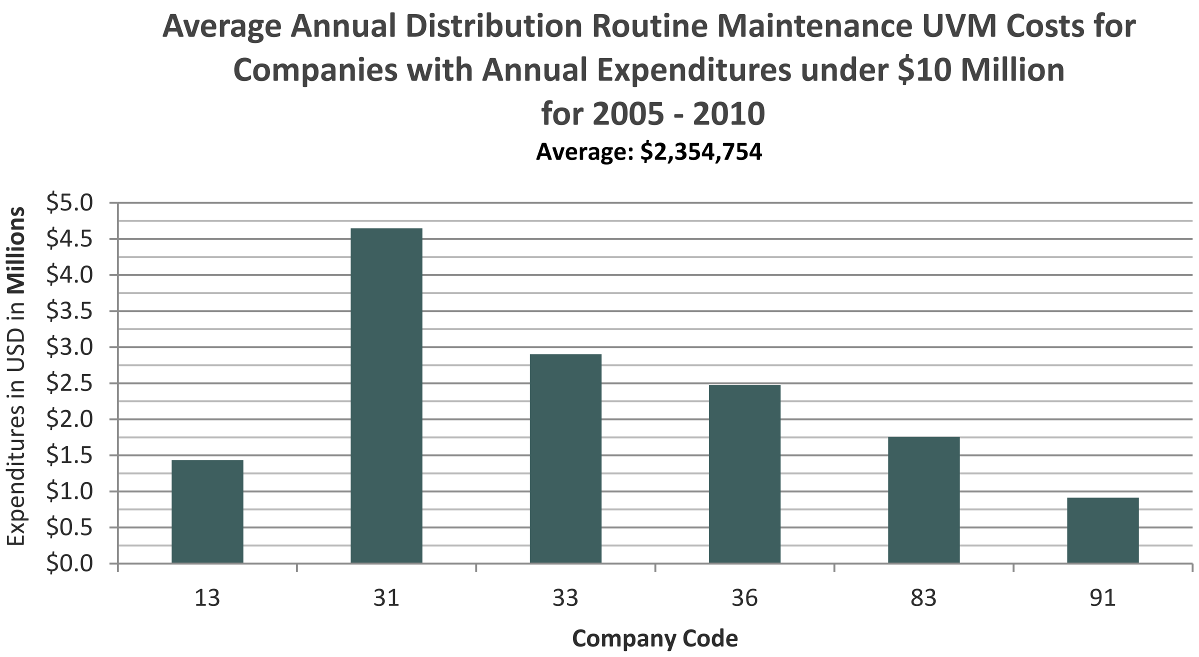

Figure 73: Average Annual Routine Maintenance UVM Costs for Companies with Annual Costs under $10 Million

Labor Hours Expended for Distribution UVM Routine Maintenance

Companies that expend greater than 200,000 hours annually have been represented separately from the companies that expend less than 200,000 hours annually.

Data collected from responses to **Question #101**

Labor Hours Expended for Routine Maintenance for Companies with Greater Than 200,000

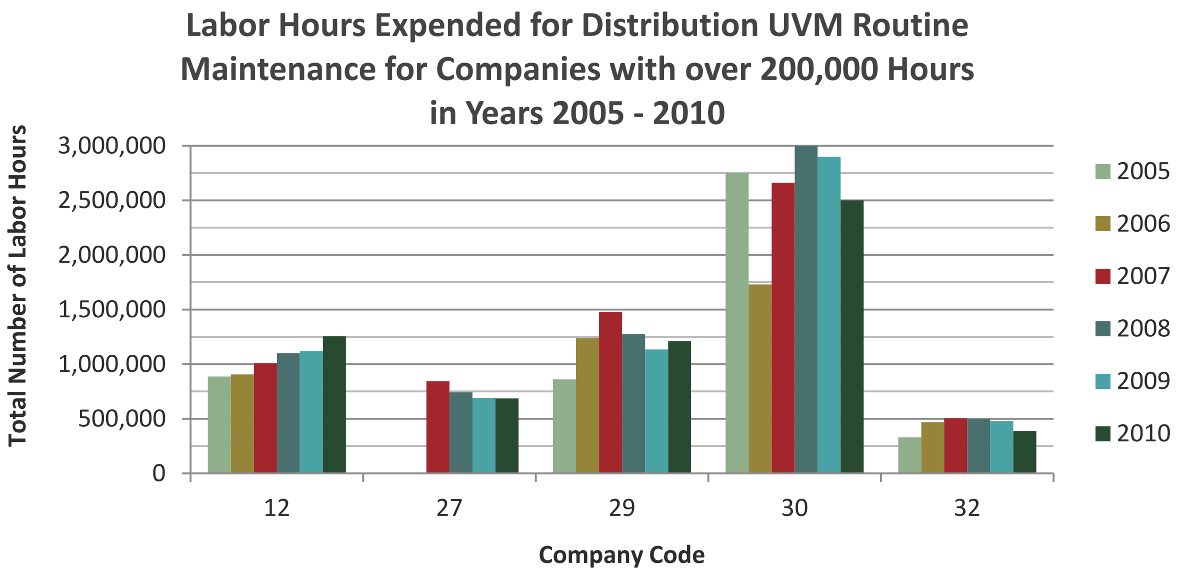

Figure 74: Labor Hours Expended for UVM Routine Maintenance for Companies with over 200,000 Hours

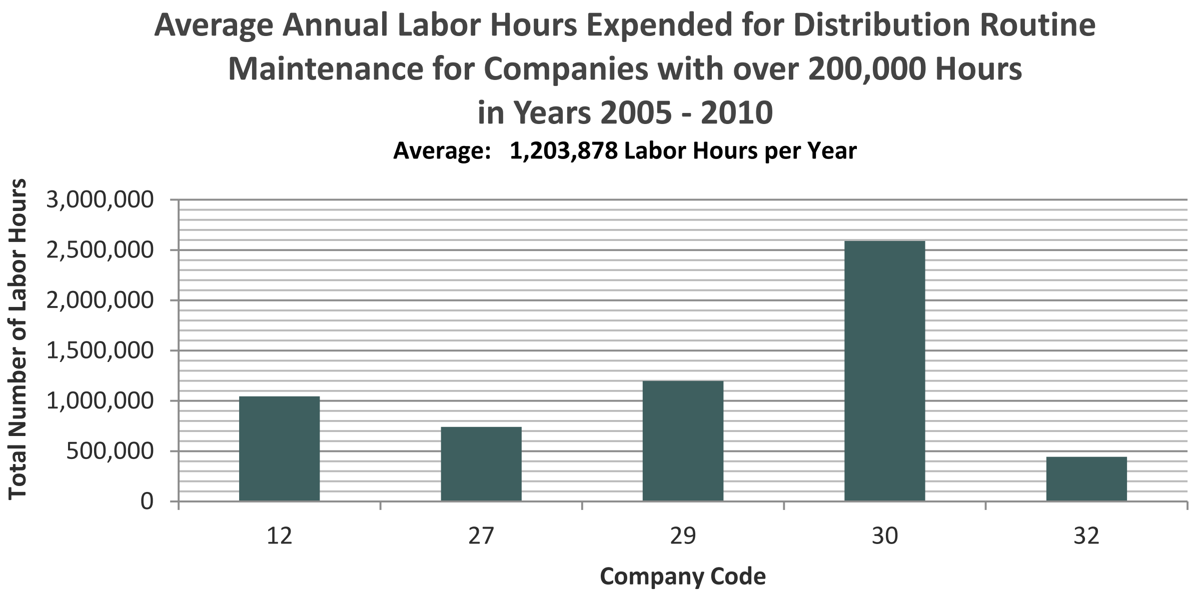

Figure 75: Average Annual Labor Hours Expended for Routine Maintenance for Companies with over 200,000 Hours

Labor Hours Expended for Routine Maintenance for Companies with Fewer Than 200,000

Data collected from responses to **Question #101**

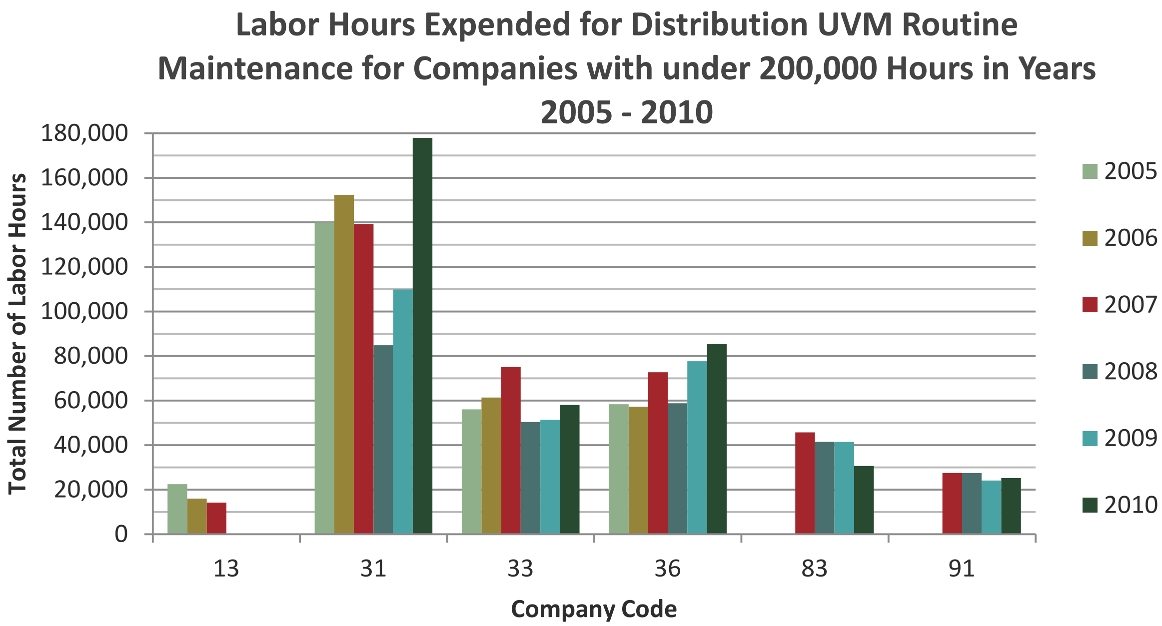

Figure 76: Labor Hours Expended for UVM Routine Maintenance for Companies with Fewer Than 200,000 Hours

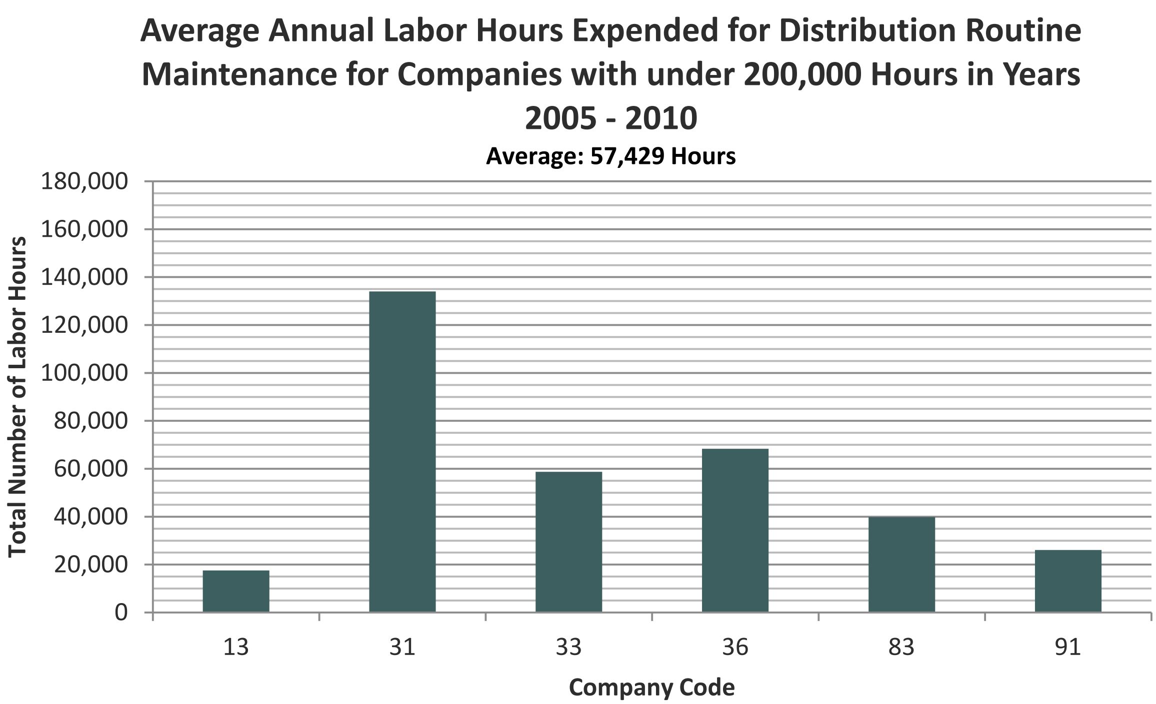

Figure 77: Labor Hours Expended for Routine Maintenance for Companies with Fewer Than 200,000 Hours in Years

Average Cost per Labor Hour for Distribution Routine Maintenance

Data collected from responses to **Question #101**. This is a calculated statistic from reported labor hours and reported expenditures (labor and equipment) for distribution routine maintenance.

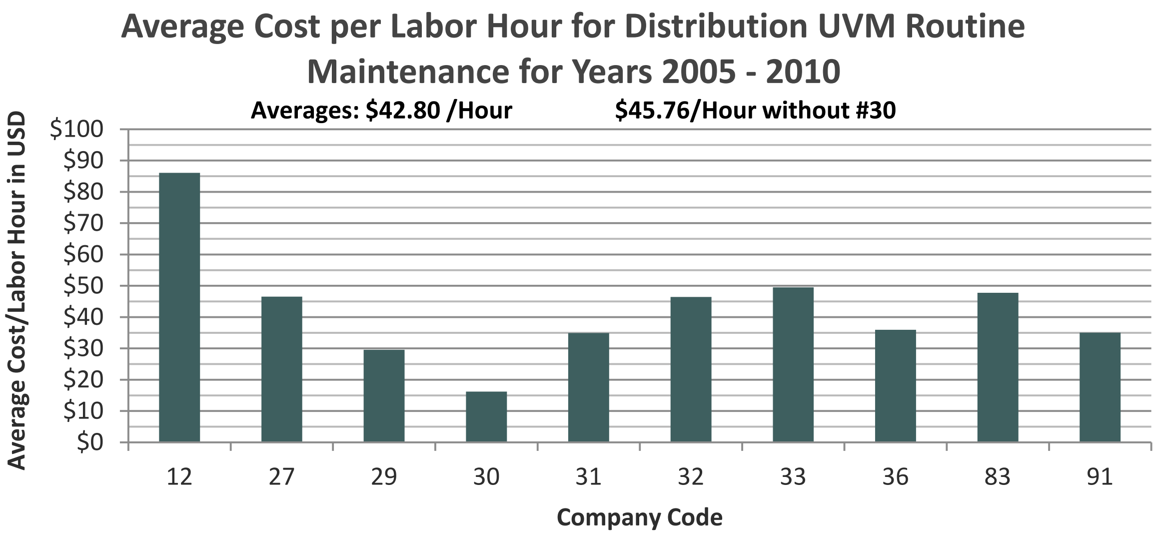

Figure 78: Average Cost per Labor Hour for UVM Routine Maintenance for Years 2005 – 2010

Percent of Total Distribution UVM Expenditures Spent on Routine Maintenance

Statistics calculated from data collected from responses to **Question #101** and **Question #96**. Two graphs follow.

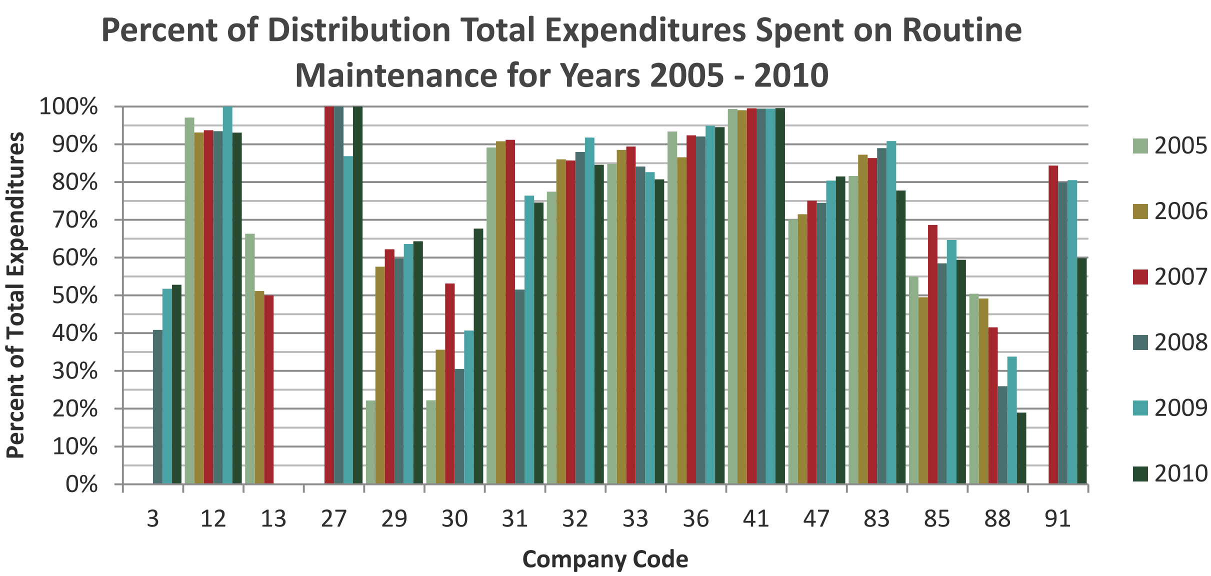

Figure 79: Percent of Total Expenditures Spent on UVM Routine Maintenance for Years 2005 - 2010

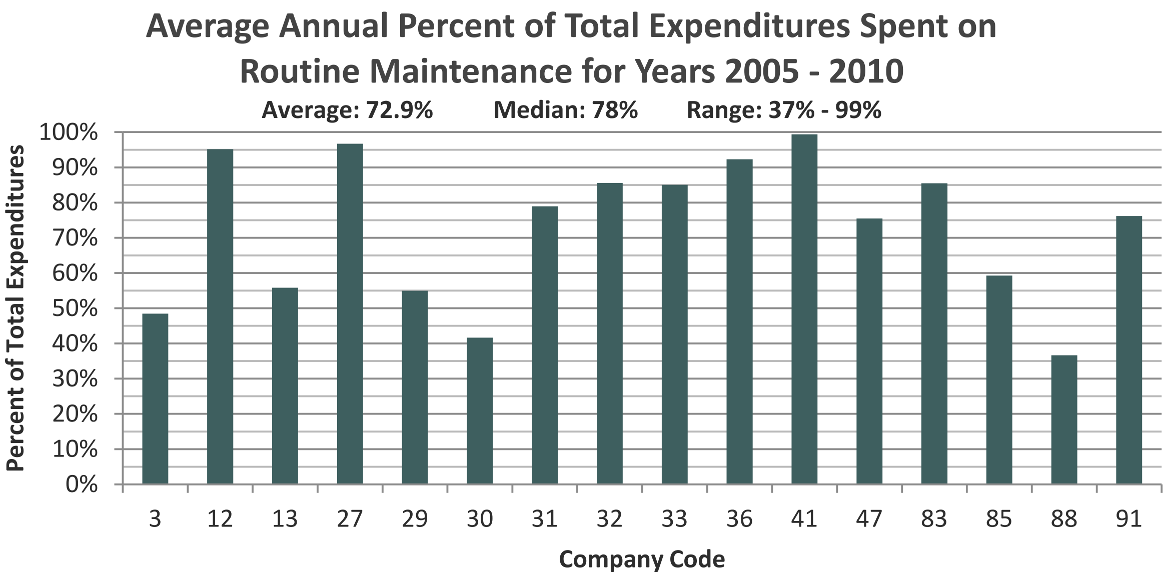

Figure 80: Average Annual Percent of Total Expenditures Spent on Routine Maintenance for Years 2005 - 2010

Data Discussion on Reported Routine Maintenance

A program which spends the majority of their budget on routine maintenance may indicate a more effective approach to preventative vegetation management.

UNPLANNED OR REACTIVE UVM WORK EXPENDITURES AND LABOR HOURS

Question #103: Distribution UNPLANNED or REACTIVE WORK EXPENDITURES: This pertains to all unplanned UVM activities and includes such items as off-cycle requests, reliability work, and outbreaks of tree mortality caused by insects, disease, winter kill, drought etc. This does not include routine clearing for new construction or storm work.   Please enter the annual costs and labor hours expended for UNPLANNED WORK for the following years.

Unplanned Distribution UVM Expenditures

Annual Unplanned Expenditures for Utilities with Costs Greater Than $1 Million

Graphs are derived from information taken from **Question #103,** above. The graphs are separated into companies that spend more than one million dollars annually for reactive UVM and companies that spend less than one million dollars annually.

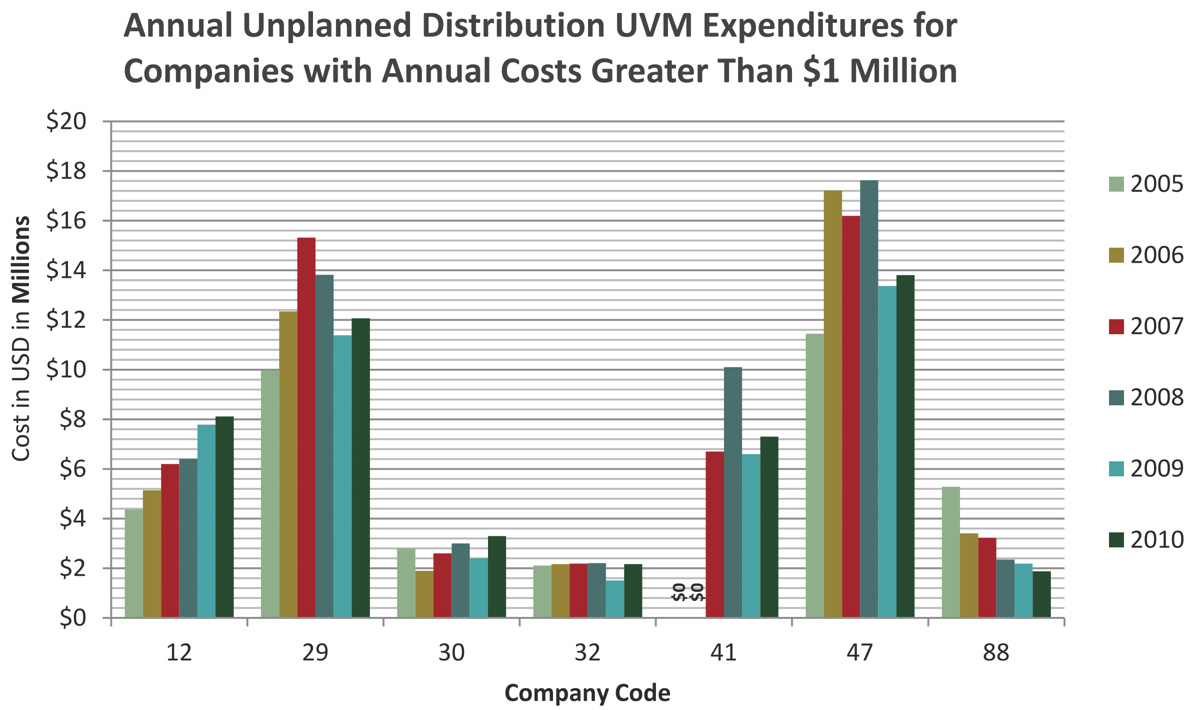

Figure 81: Annual Unplanned UVM Expenditures for Companies with Annual Costs Greater Than $1 Million

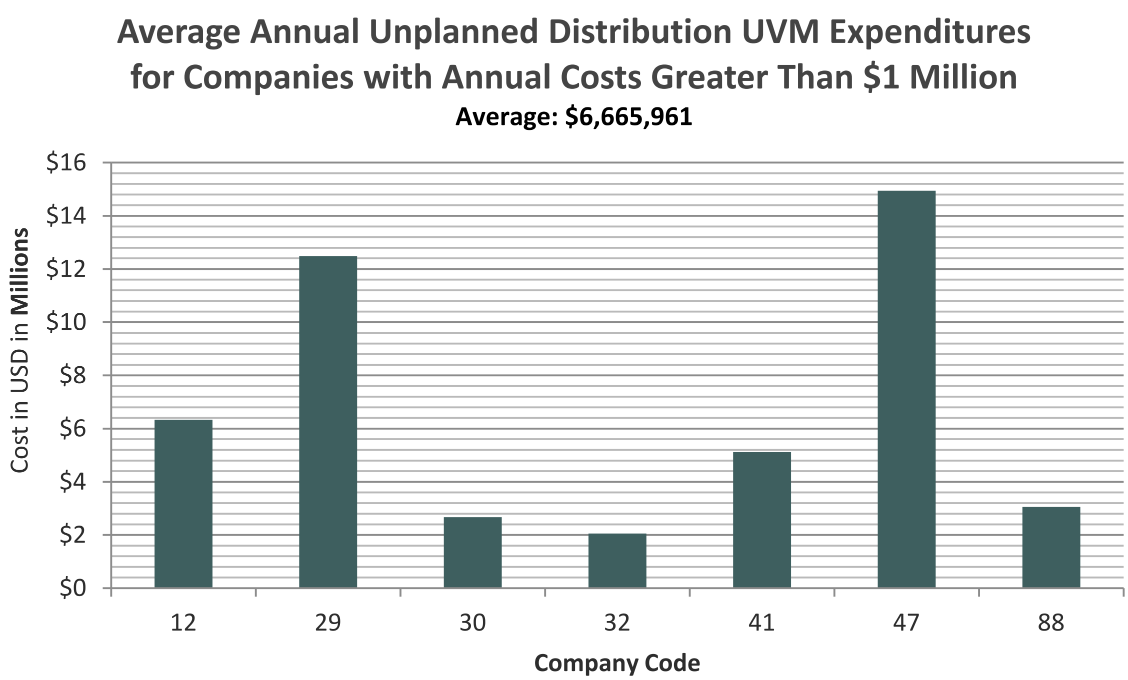

Figure 82: Average Annual Unplanned UVM Expenditures for Companies with Annual Costs Greater Than $1 Million

Annual Unplanned UVM Expenditures for Utilities with Costs Less Than $1 Million

Data Collected from responses to **Question #103**

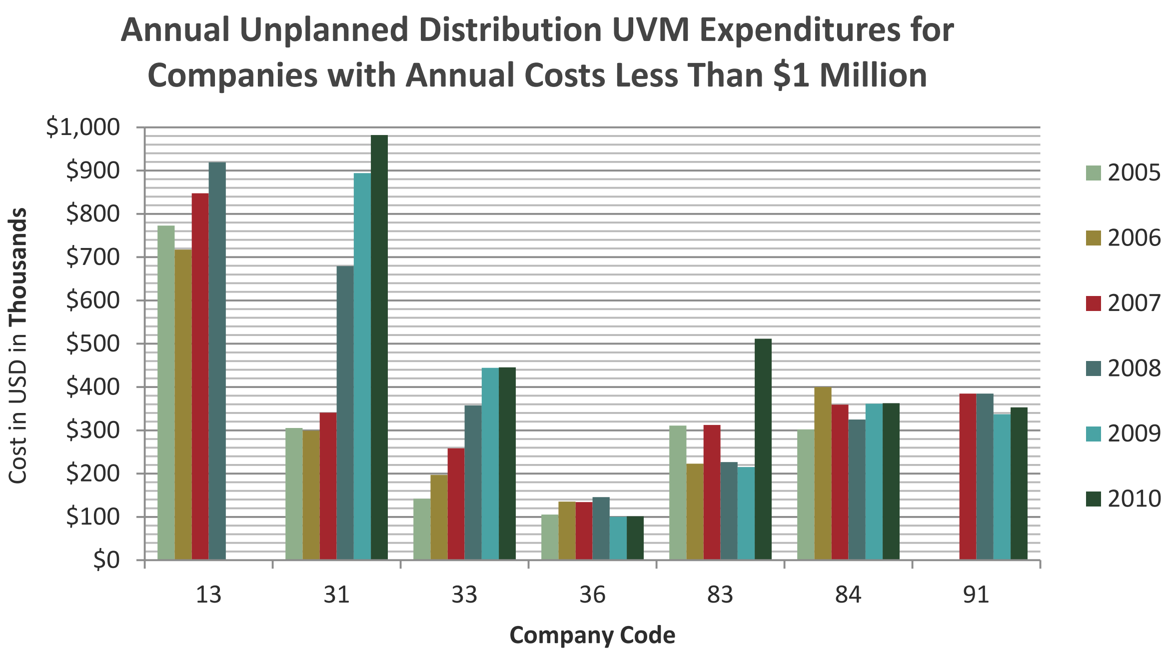

Figure 83: Annual Unplanned UVM Expenditures for Companies with Annual Costs Less Than $1 Million

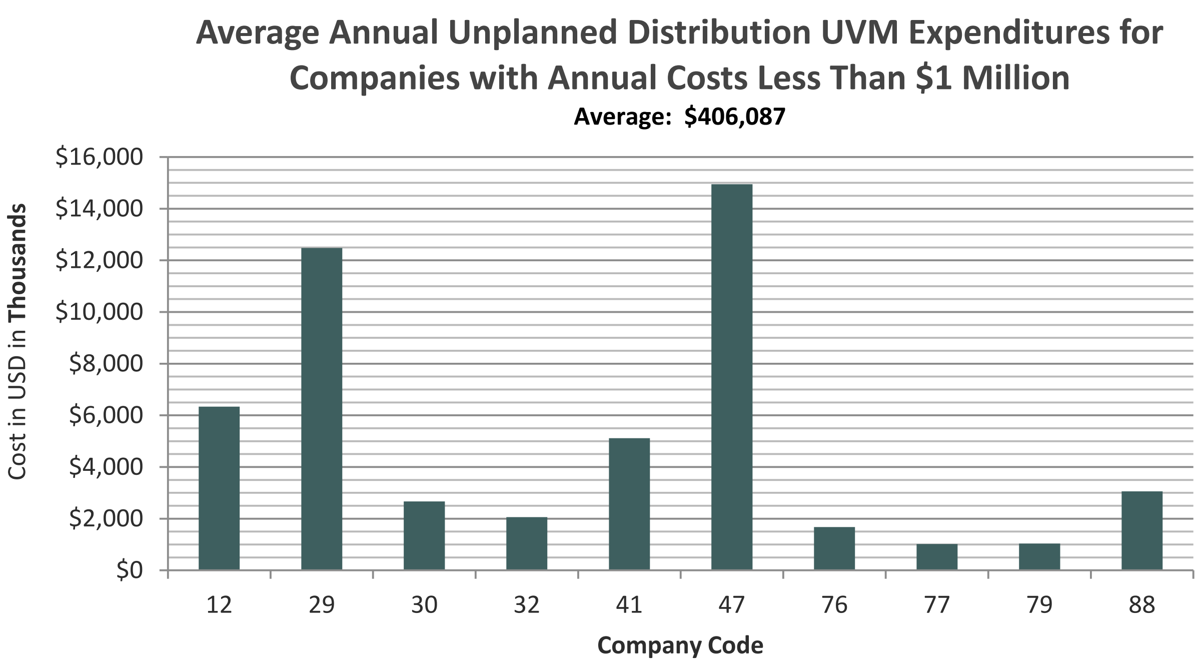

Figure 84: Average Annual Unplanned UVM Expenditures for Companies with Annual Costs Less Than $1 Million

Labor Hours Expended for Unplanned Distribution UVM

Companies that expend greater than 25,000 hours annually have been represented separately from the companies that expend less than 25,000 hours annually.

Data collected from responses to **Question #103**

Labor Hours Expended for Unplanned UVM for Companies with Greater Than 25,000

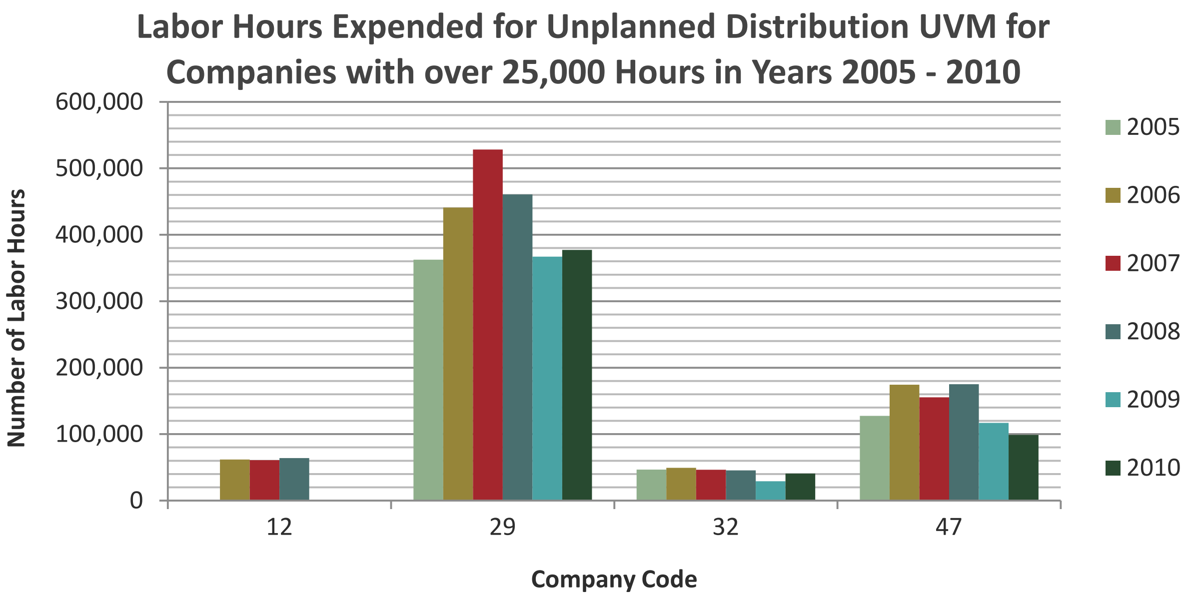

Figure 85: Labor Hours Expended for Unplanned UVM for Companies Greater Than 25,000 Hours

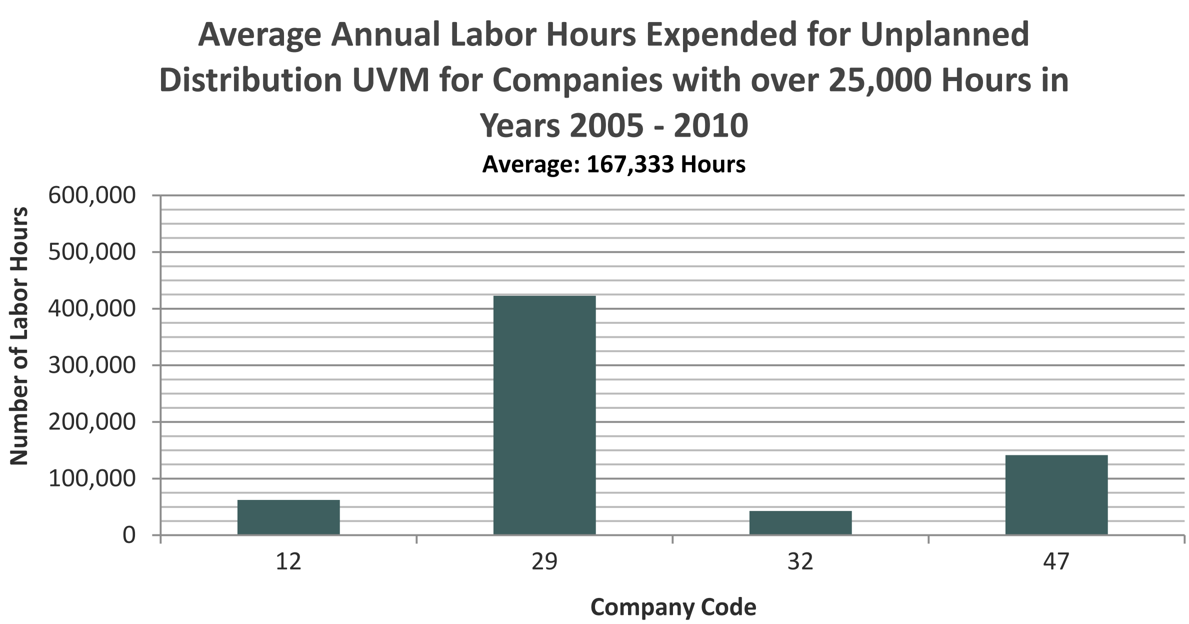

Figure 86: Average Annual Labor Hours Expended for Unplanned UVM for Companies Greater Than 25,000 Hours

Data collected from responses to **Question #103**

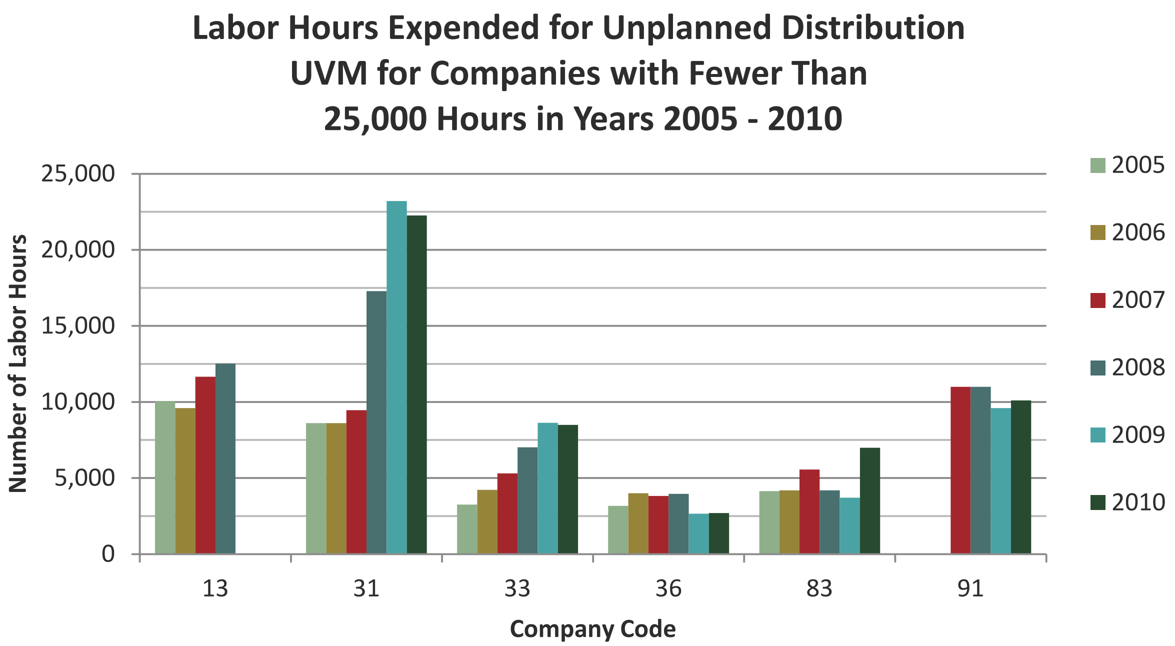

Figure 87: Labor Hours Expended for Unplanned UVM for Companies Fewer Than 25,000 Hours

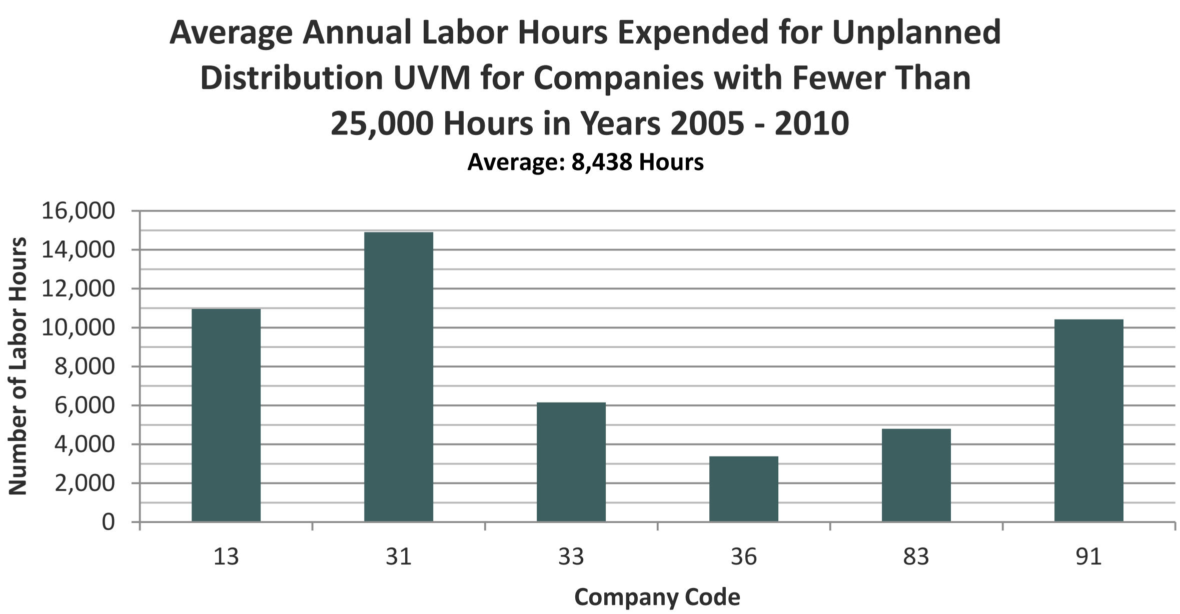

Figure 88: Average Annual Labor Hours Expended for Unplanned UVM for Companies Fewer Than 25,000 Hours

Average Cost per Labor Hour for Distribution UVM Reactive Work

Data collected from responses to **Question #103**. This is a calculated statistic from reported labor hours and reported expenditures for distribution UVM reactive work.

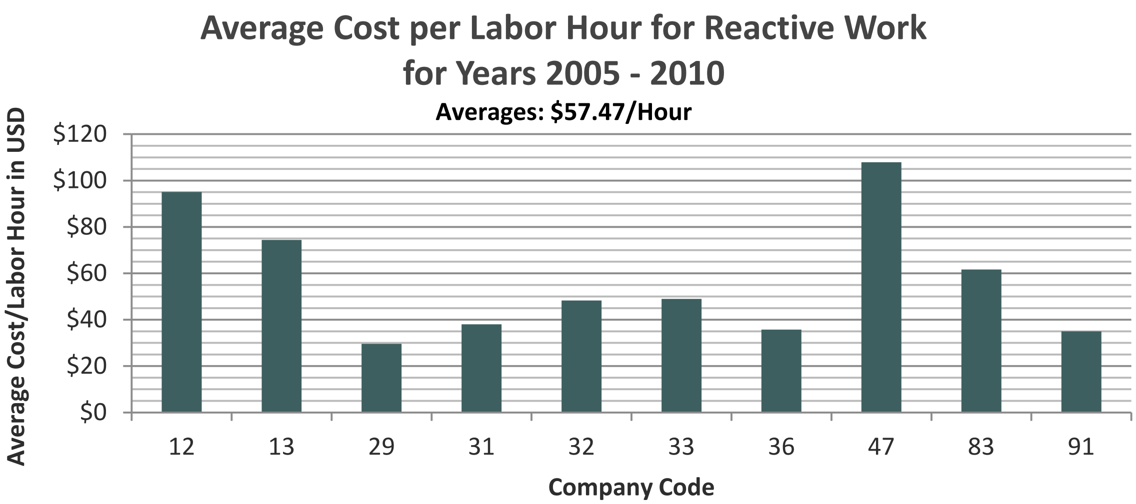

Figure 89: Average Cost per Labor Hour for UVM Reactive Work for Years 2005 - 2010

Percent of Total Distribution UVM Expenditures Spent on Reactive Work

Statistics calculated from data collected from responses to **Question #103** and **Question #96**. Two graphs follow.

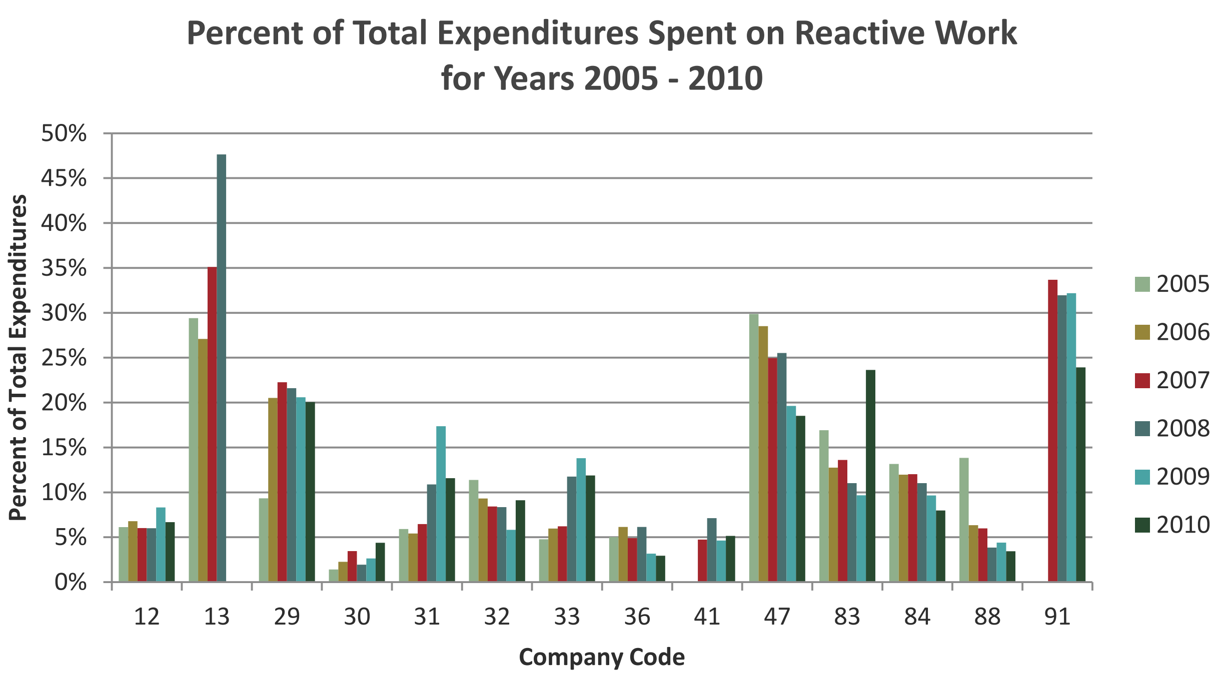

Figure 90: Percent of Total Expenditures Spent on UVM Reactive Work for Years 2005 - 2010

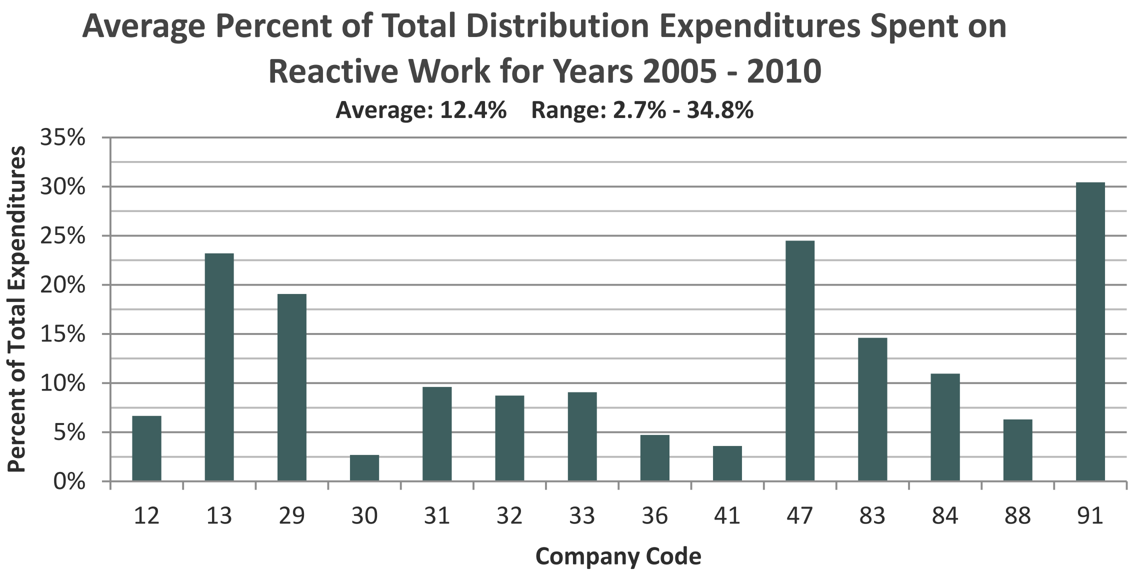

Figure 91: Average Percent of Total Expenditures Spent on UVM Reactive Work for Years 2005 - 2010

Comments on Unplanned Distribution UVM

Data collected from responses to **Question #103**

Comments on Unplanned UVM
Customer requests and reliability work
Reliability Improvement Program
Don't separate storm work from other unplanned or reactive work [Not represented in previous section's graphs]
No data
Includes Mid-Cycle
Nuisance calls are 40% of off cycle trimming and removals.
Those actual hours are entrepreneur's [contractor] hours only. 20,000 hours for each year, can be added, if you take in consideration the time of our forest technician to coordinate our entrepreneur on those jobs.

Figure 92: Comments on Unplanned UVM

EMERGENCY STORM RESPONSE UVM EXPENDITURES AND LABOR HOURS

Question #105: EMERGENCY STORM RESPONSE AND RESTORATION EXPENDITURES: This pertains to around the clock response to emergency conditions and includes additional forestry crews brought in for storm assistance. Please enter your annual costs and labor hours expended for DISTRIBUTION STORM RESPONSE for the following years.

Distribution Emergency Storm Response UVM Expenditures

Information is taken from **Question #105** above. The graphs are separated into companies that spend more than one million dollars annually for UVM emergency storm response and restoration and companies that spend less than one million dollars annually.

Annual Storm Expenditures for Utilities with Costs Greater Than $1 Million

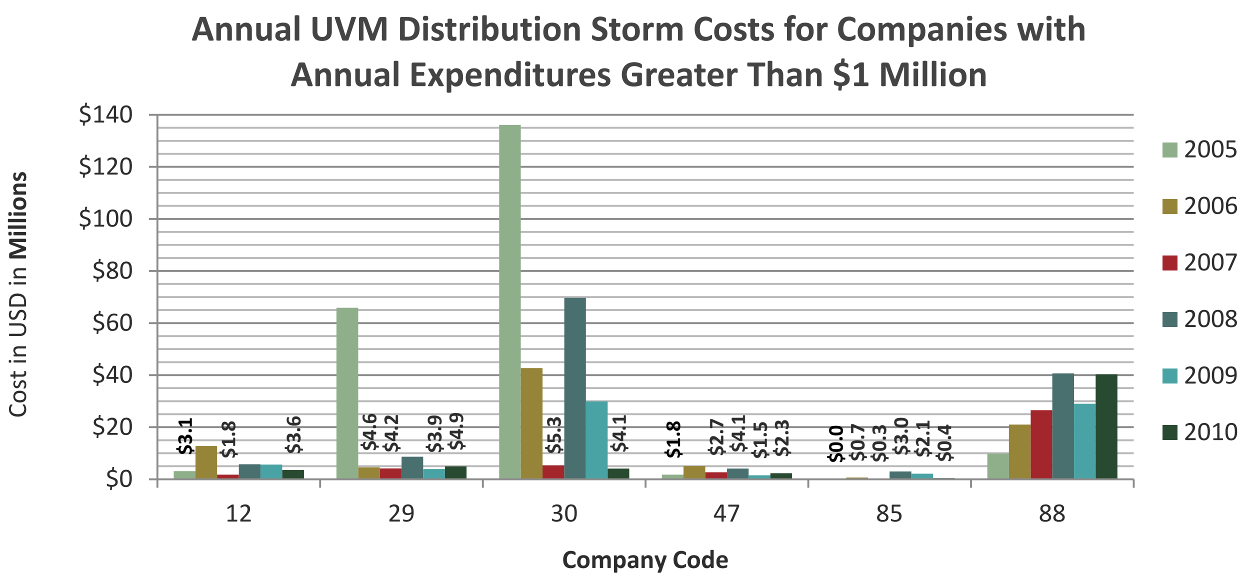

Figure 93: Annual UVM Storm Costs for Companies with Annual Expenditures Greater Than $1 Million

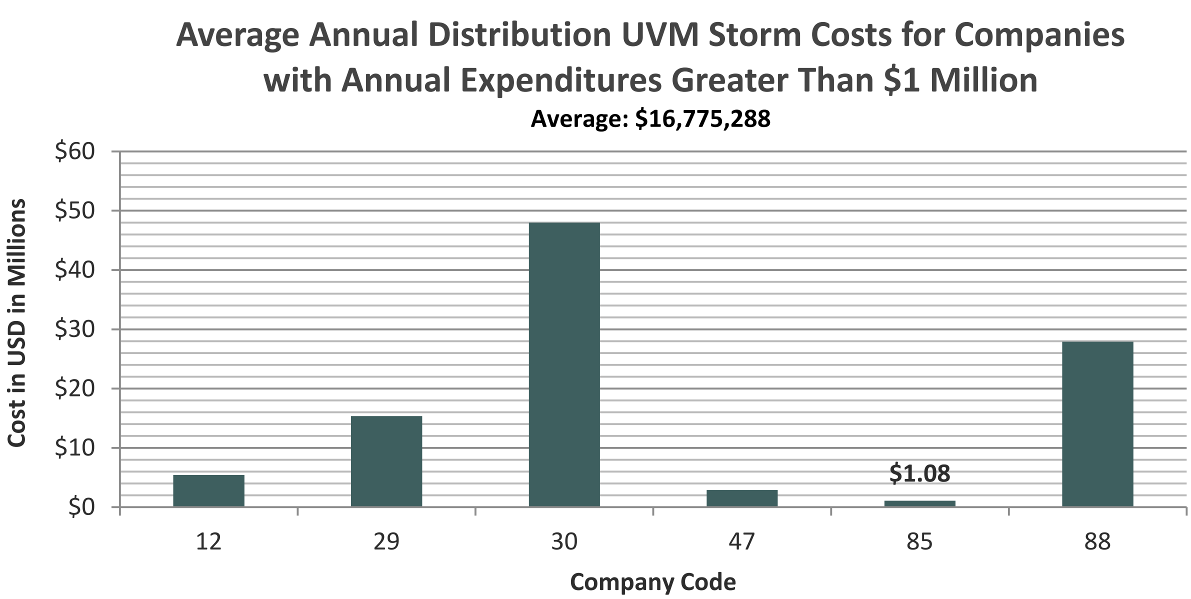

Figure 94: Average Annual UVM Storm Costs for Companies with Annual Expenditures Greater Than $1 Million

Annual Storm UVM Expenditures for Utilities with Costs Less Than $1 Million

Data Collected from responses to **Question #105**

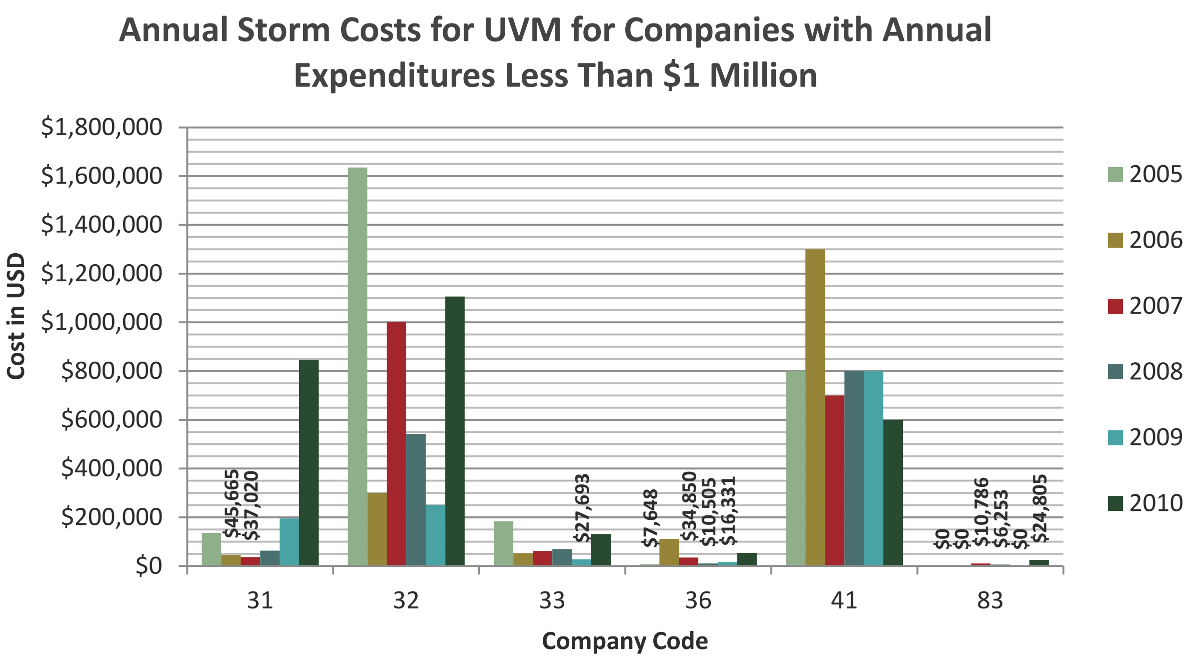

Figure 95: Annual Storm Costs for UVM for Companies with Annual Expenditures Less Than $1 Million

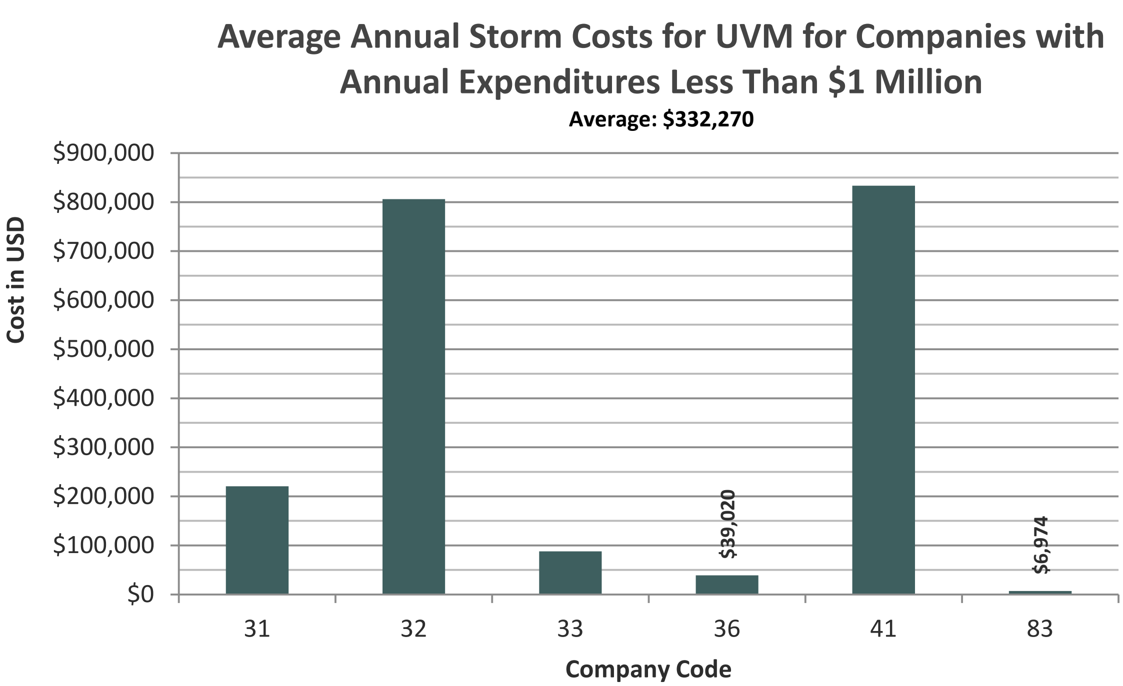

Figure 96: Average Annual Storm Costs for UVM for Companies with Annual Expenditures Less Than $1 Million

Labor Hours Expended for Emergency Storm Response UVM

Companies that expend greater than 10,000 hours annually have been represented separately from the companies that expend less than 10,000 hours annually.

Data Collected from responses to **Question #105**

Annual Storm Labor Hours Expended for Utilities with Greater Than 10,000 Hours

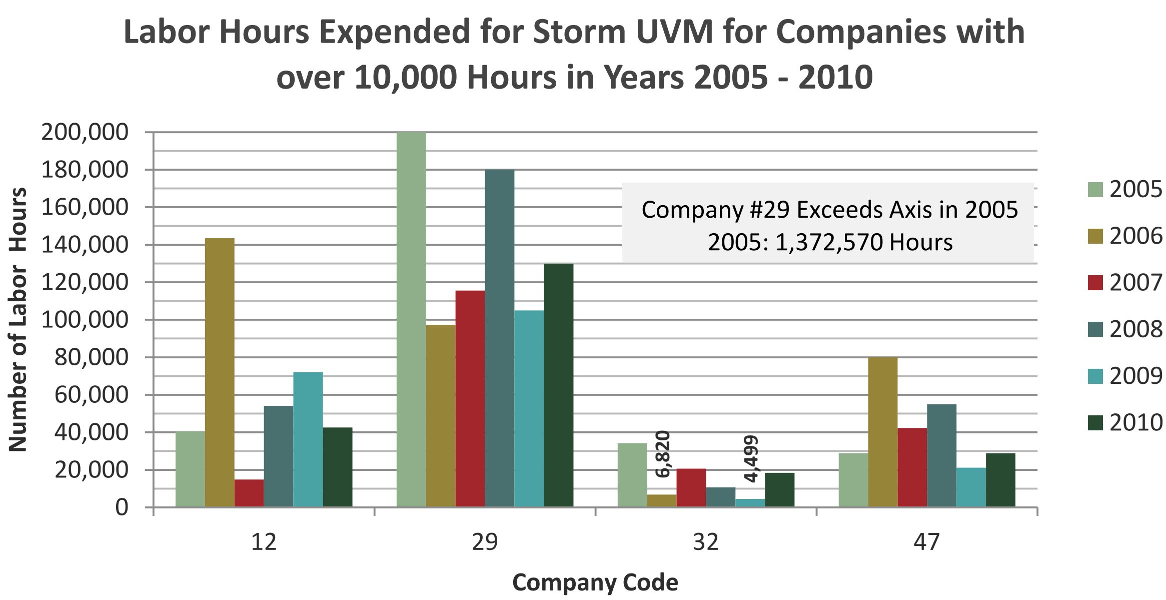

Figure 97: Labor Hours Expended for Storm UVM for Companies with over 10,000 Hours in Years 2005 - 2010

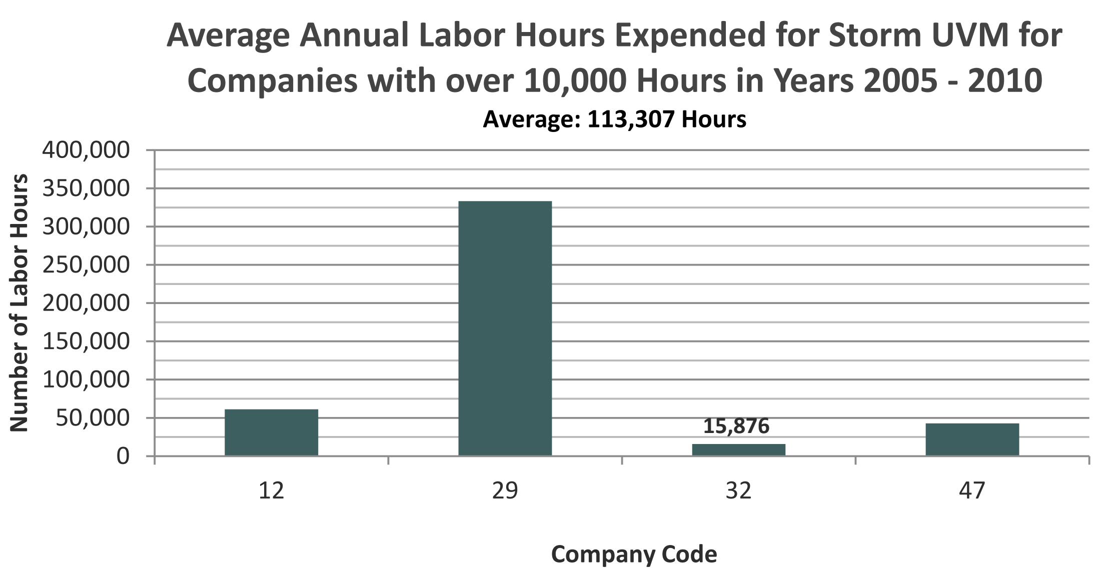

Figure 98: Average Annual Labor Hours Expended for Storm UVM for Companies with over 10,000 Hours

Annual Storm Labor Hours Expended for Utilities with Fewer Than 10,000 Hours

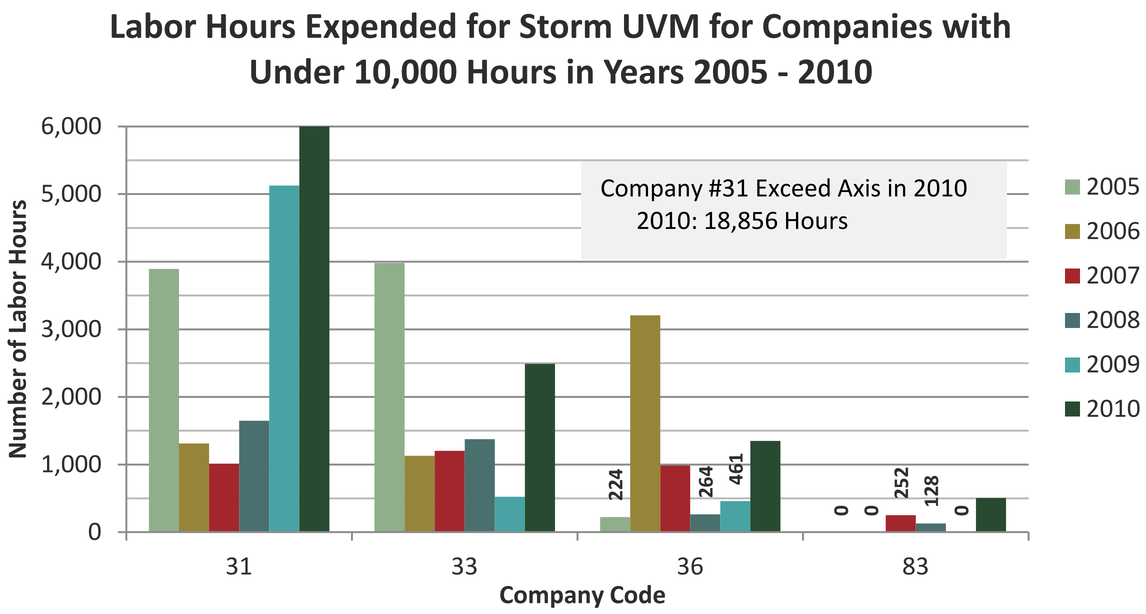

Figure 99: Labor Hours Expended for Storm UVM for Companies with Fewer Than 10,000 Hours

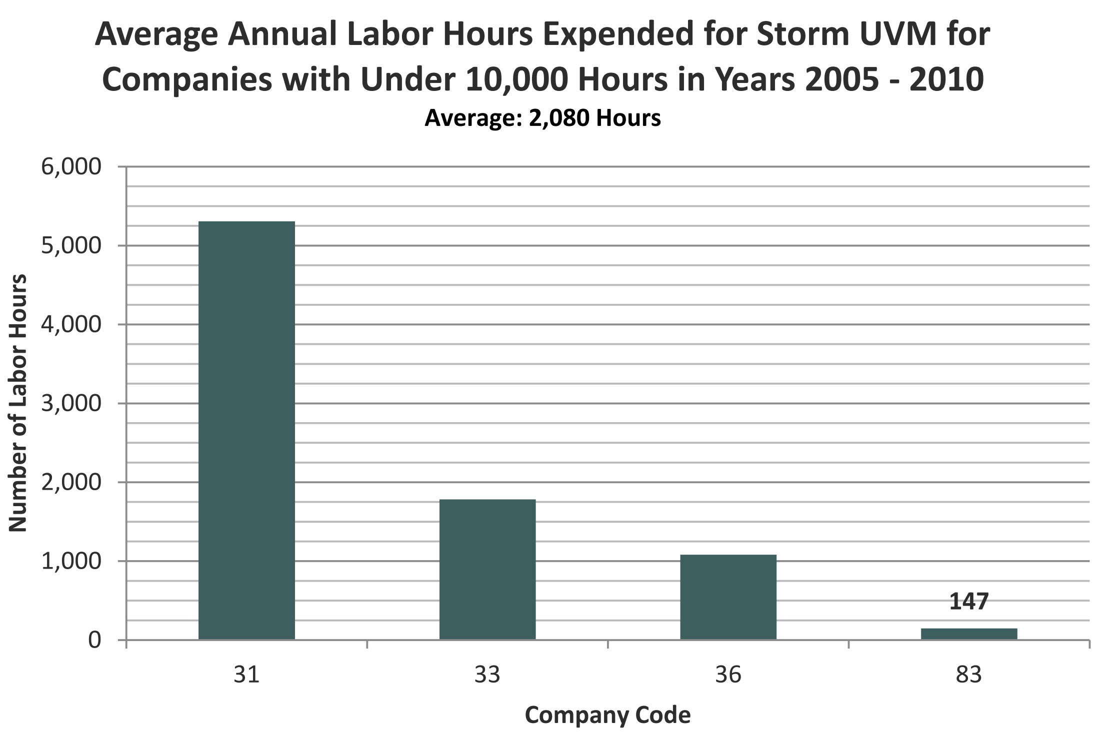

Figure 100: Average Annual Labor Hours Expended for Storm UVM for Companies with Fewer than 10,000 Hours

Average Cost per Labor Hour for Emergency Storm Response

Data collected from responses to **Question #105**. This is a calculated statistic from reported labor hours and reported expenditures for distribution UVM emergency storm response and restoration work.

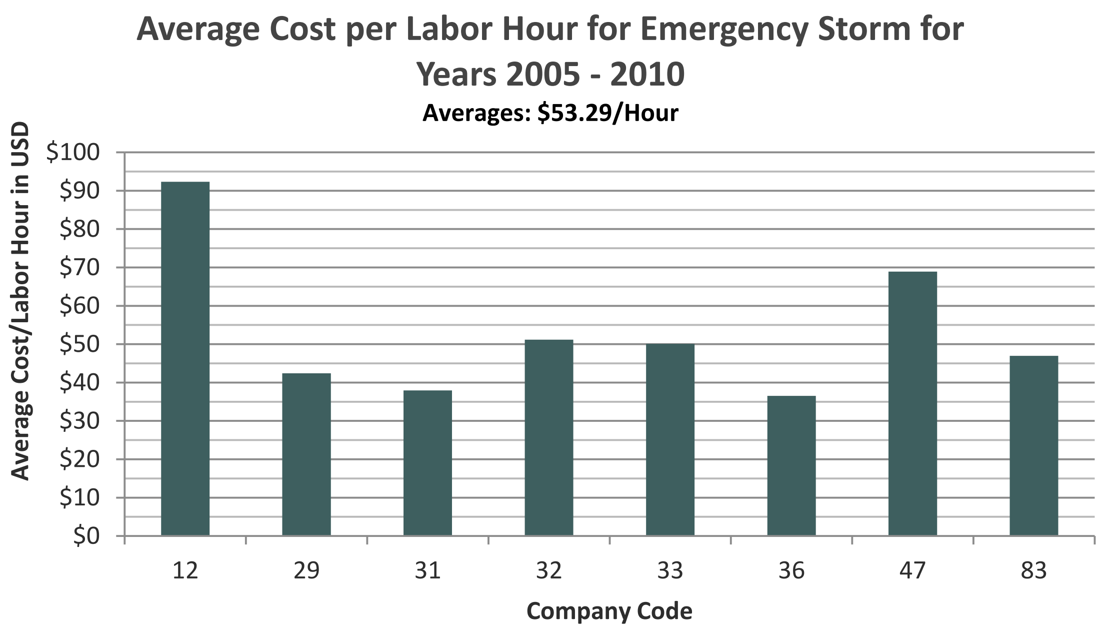

Figure 101: Average Cost per Labor Hour for Emergency Storm for Years 2005 - 2010

Percent of Total UVM Expenditures Spent on Emergency Storm Response

Statistics calculated from data collected from responses to **Question #105** and **Question #96**. Two graphs follow.

Note: Many utilities pay for UVM storm restoration from a separate budget. As one participant noted, "Storm cost was recoverable expense." Due to these variations, not all companies include storm costs with their total UVM expenditures. When viewing the following two graphs, keep this fact in mind.

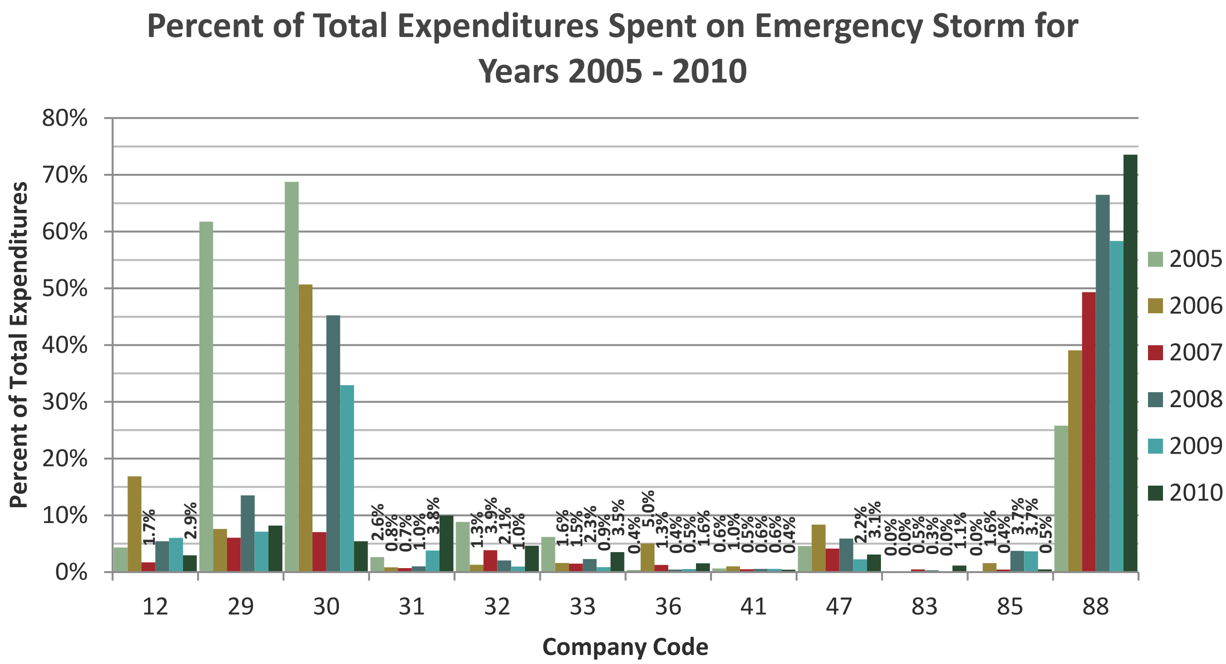

Figure 102: Percent of Total Expenditures Spent on Emergency Storm for Years 2005 - 2010

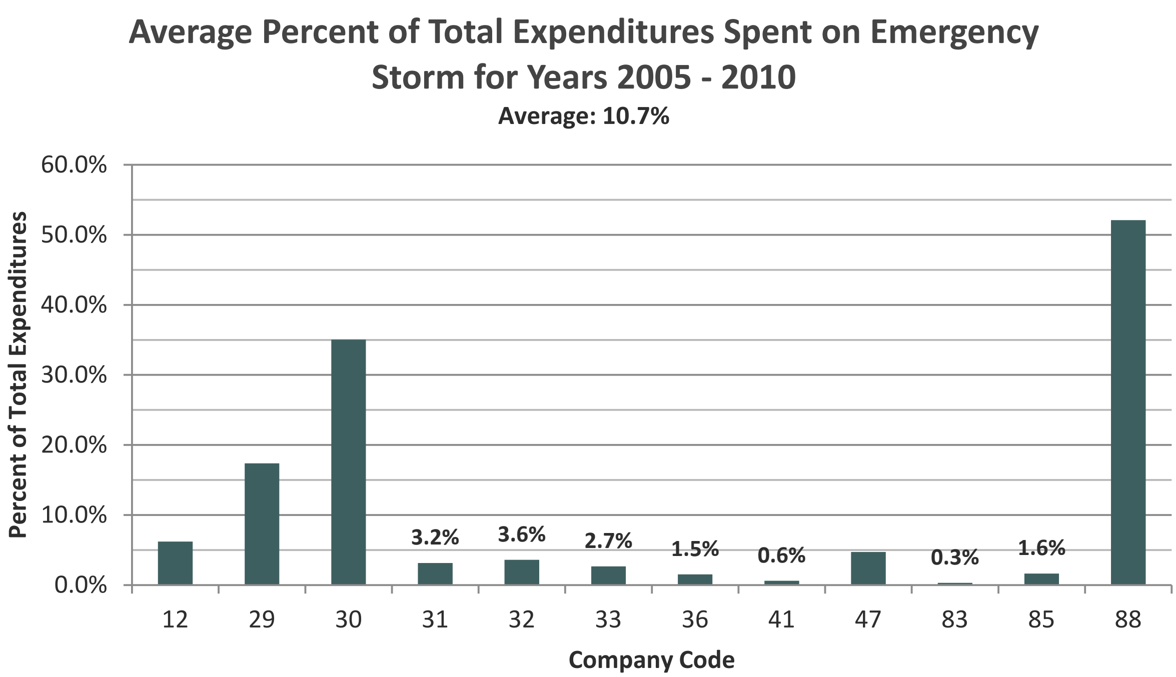

Figure 103: Average Percent of Total Expenditures Spent on Emergency Storm for Years 2005 – 2010

Comments on Emergency Storm Response UVM

Data Collected from responses to **Question #105**

Comments on UVM Emergency Storm Response and Restoration
Don't separate storm work and restoration work from other unplanned or reactive work
No data
Note: 2005 Storm cost was recoverable expense
No foreign crews brought in.
In-house Line crews and guest line crews during storm situations also do emergency tree work, but the cost is not captured.
Those actual hours are entrepreneur's hours only.
Costs estimated using average $/Hr from 2009 benchmarking results

Figure 104: Comments on UVM Emergency Storm Response and Restoration

Data Discussion on Emergency Storm Response UVM

Some observations about emergency storm response expenditures and labor hours expended:

1. It is apparent that some companies experience expenditure spikes due to extreme weather events.
2. It is noteworthy that some companies have consistently high costs for emergency response and other companies are consistently low. This could indicate differences in UVM programs and expenditure reporting, but it is likely a reflection of geographical storm tracks.

NEW CONSTRUCTION UVM EXPENDITURES AND LABOR HOURS

Question # 107: NEW CONSTRUCTION EXPENDITURES: This pertains to any vegetation management work done to clear for the construction of new distribution lines. Please enter your annual costs and labor hours expended on NEW CONSTRUCTION for the following years.

New Construction UVM Expenditures

The graphs are separated into companies that spend more than one million dollars annually and companies that spend less than one million dollars annually.

Annual New Construction UVM Expenditures for Utilities with Costs Greater Than $1 Million

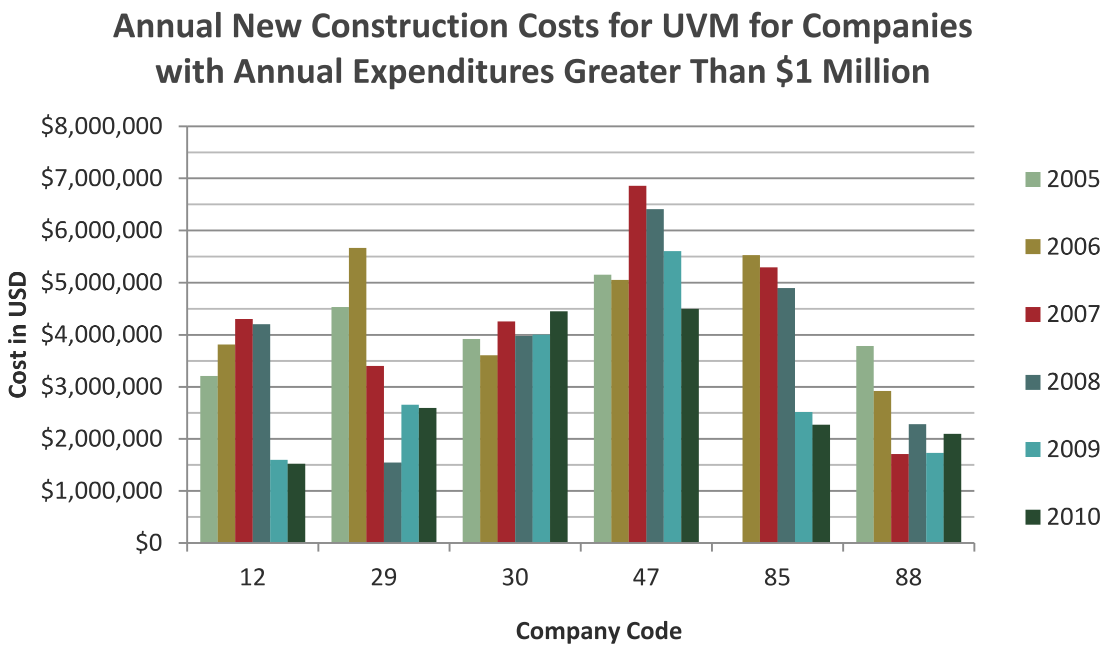

Figure 105: Annual New Construction UVM Costs for Companies with Annual Expenditures Greater Than $1 Million

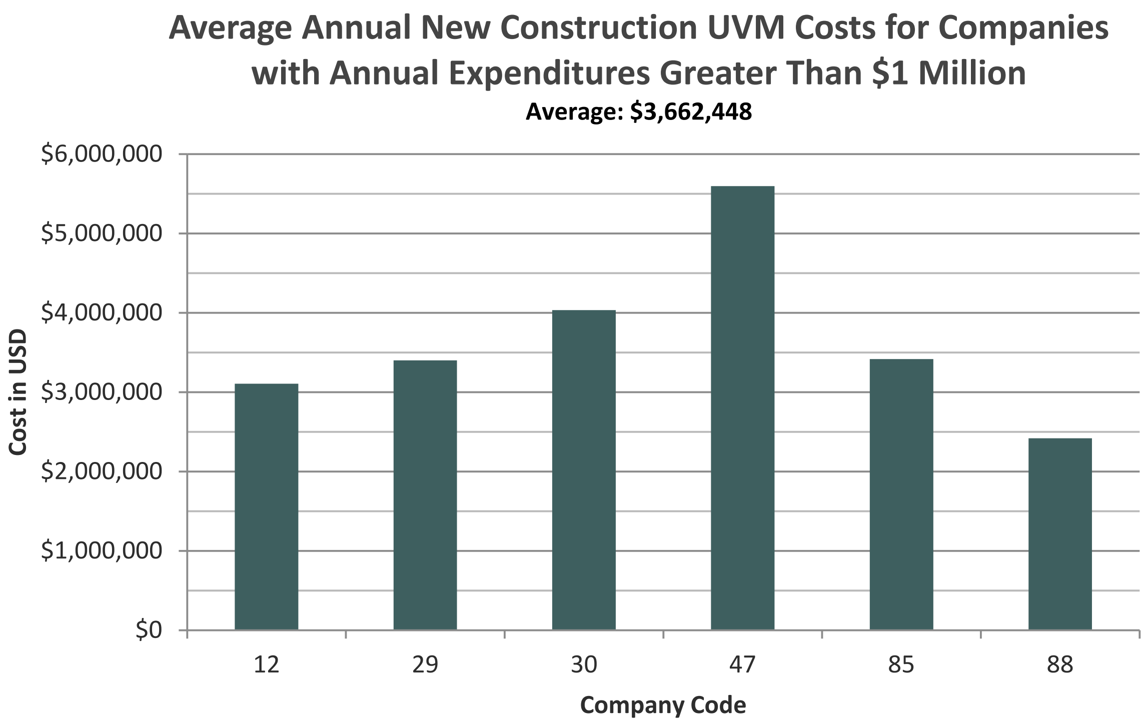

Figure 106: Average Annual New Construction UVM Costs for Companies with Expenditures Greater Than $1 Million

Annual New Construction UVM Expenditures for Utilities with Costs Less Than $1 Million

Data Collected from responses to **Question#107**

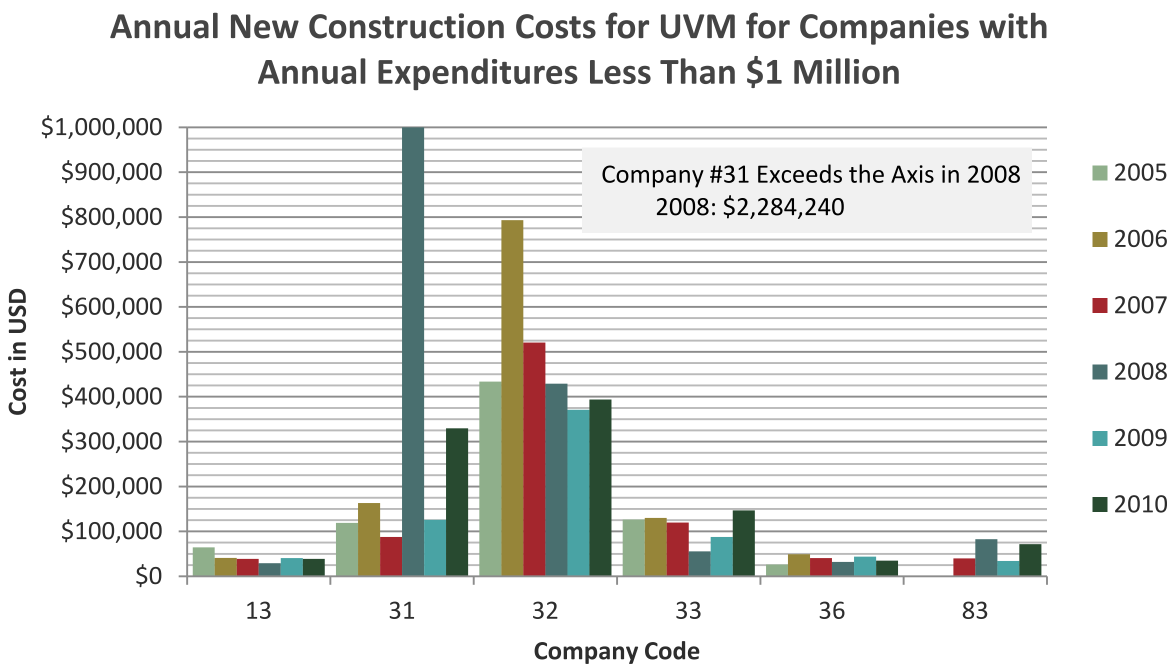

Figure 107: Annual New Construction Costs for UVM for Companies with Annual Expenditures Less Than $1 Million

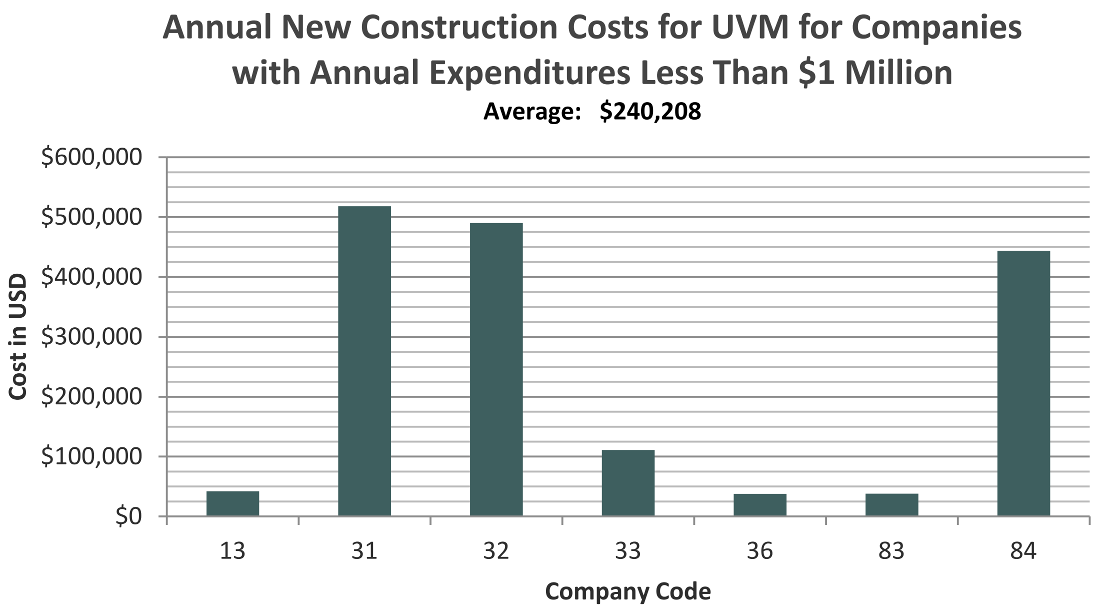

Figure 108: Annual New Construction Costs for UVM for Companies with Annual Expenditures Less Than $1 Million

Labor Hours Expended for New Construction UVM

Companies that expend greater than 20,000 hours annually have been represented separately from the companies that expend less than 20,000 hours annually.

Data Collected from responses to **Question#107**

Annual New Construction Labor Hours Expended for Utilities with Hours over 20,000

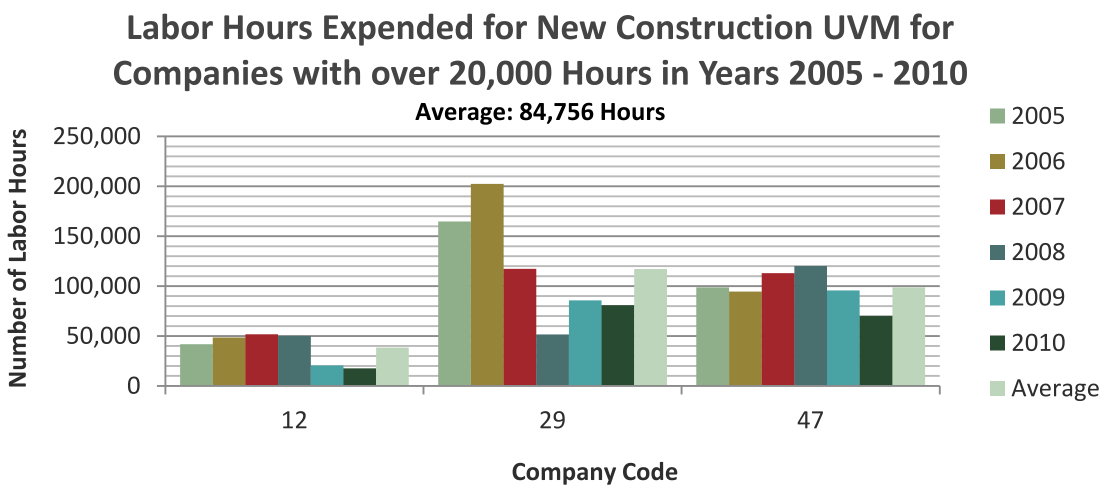

Figure 109: Labor Hours Expended for New Construction UVM for Companies with over 20,000 Hours

Annual New Construction UVM Labor Hours Expended for Utilities with Hours under 20,000

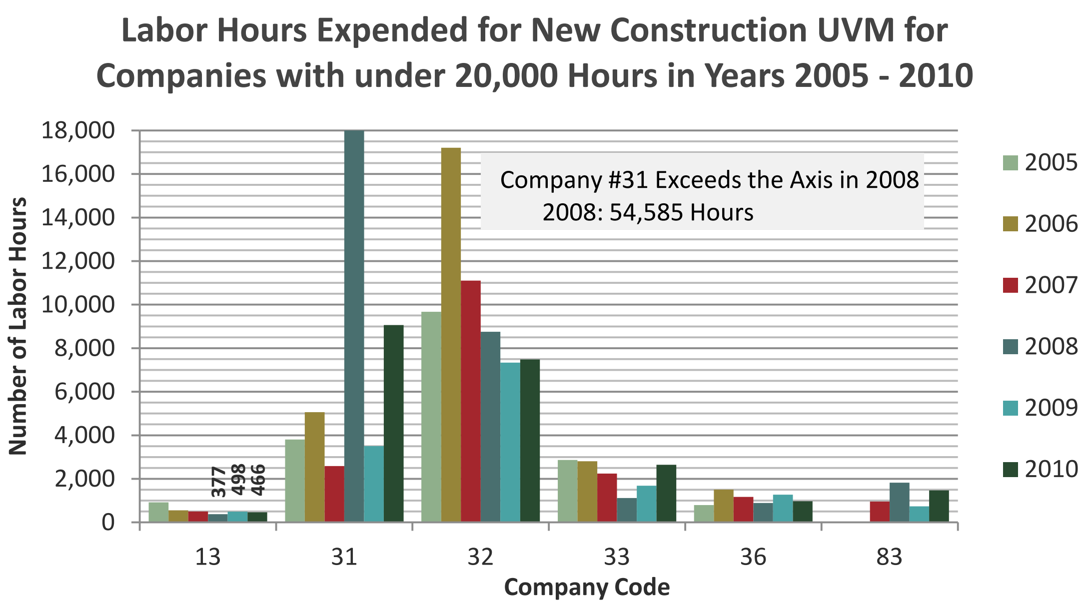

Figure 110: Labor Hours Expended for New Construction UVM for Companies with Less Than 20,000 Hours

Data Collected from responses to **Question#107**

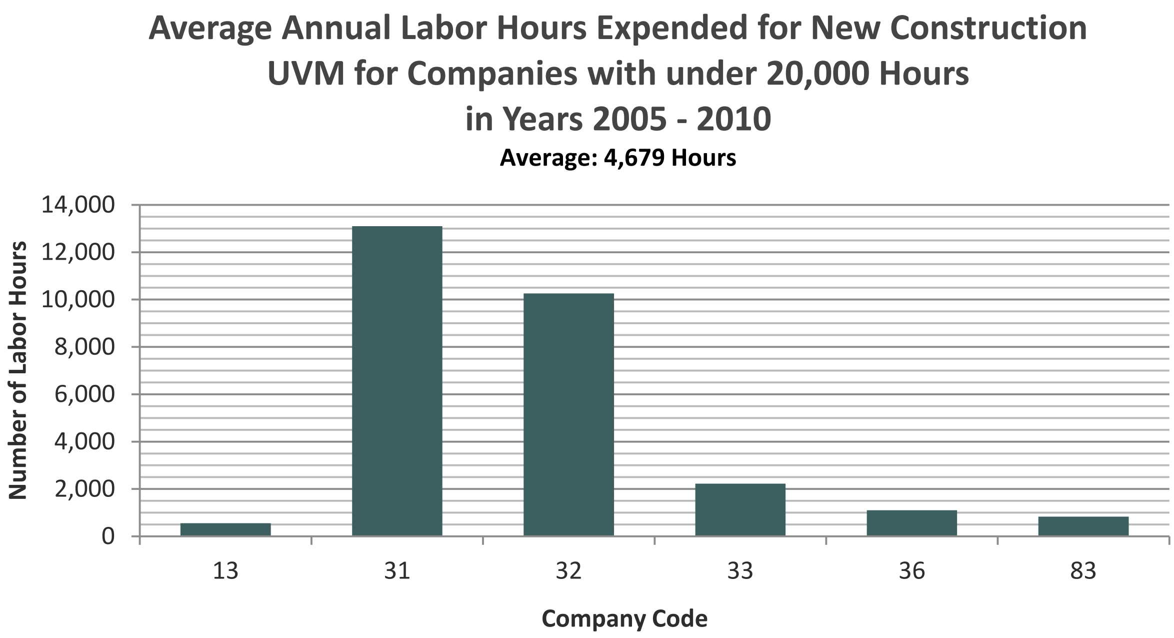

Figure 111: Average Labor Hours Expended for New Construction UVM for Companies with Less Than 20,000 Hours

Average Cost per Labor Hour for New Construction UVM

Data collected from responses to **Question#107**. This is a calculated statistic from reported labor hours and reported expenditures for distribution new construction UVM.

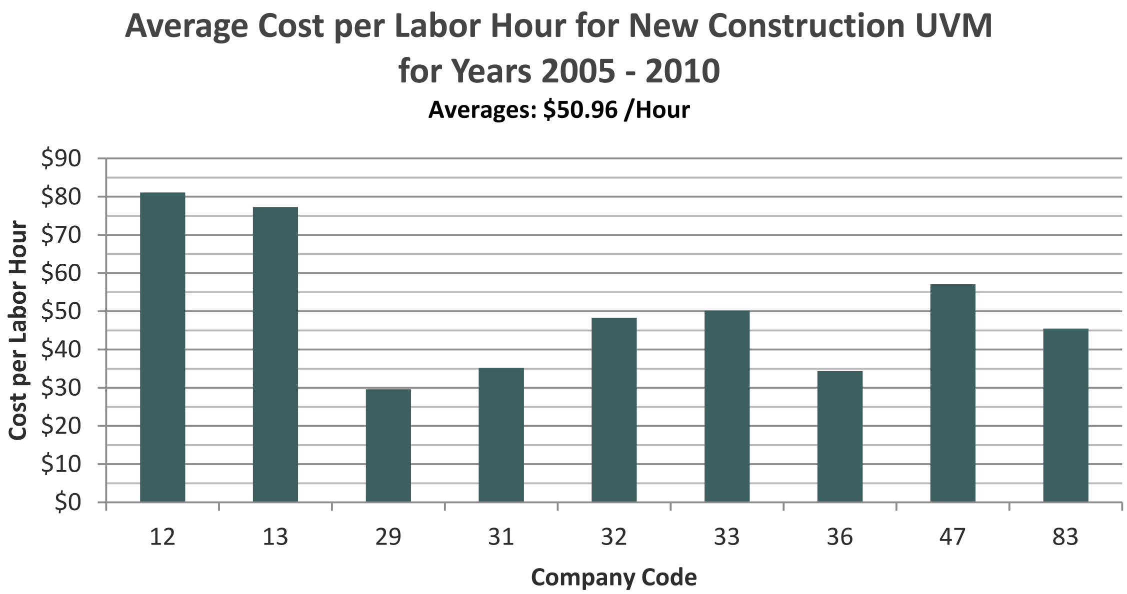

Figure 112: Average Cost per Labor Hour for New Construction UVM for Years 2005 - 2010

Percent of Total UVM Expenditures Spent on New Construction UVM

Statistics calculated from data collected from responses to **Question#107** and **Question #96**. Two graphs follow.

Note: Many utilities pay for UVM for new construction from a separate budget. As one participant noted, "These costs are not included in the vegetation budget." Due to these variations, not all companies include new construction with their total UVM expenditures. When viewing the following two graphs, keep this fact in mind.

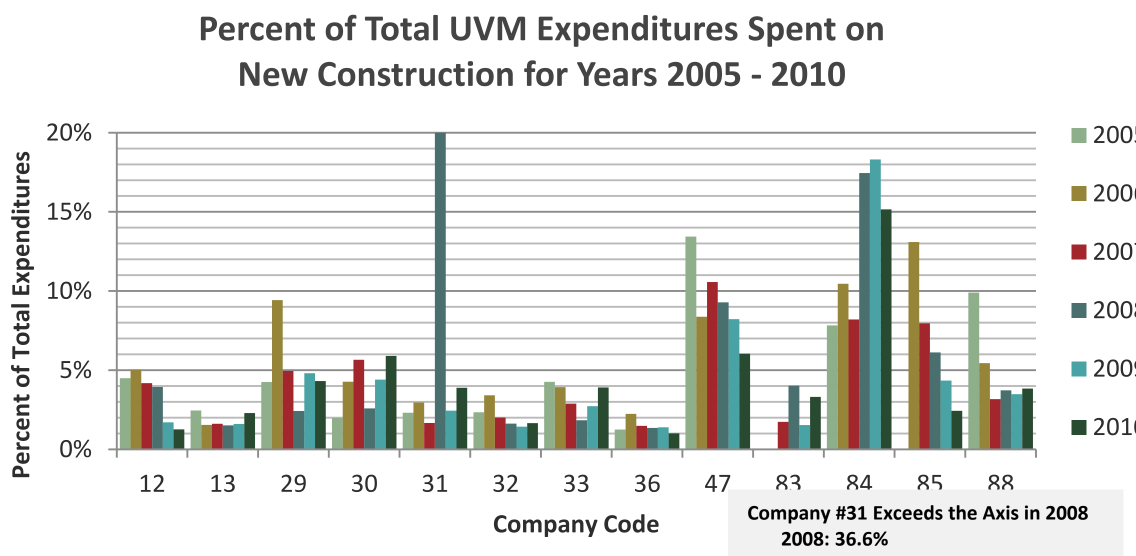

Figure 113: Percent of Total UVM Expenditures Spent on New Construction for Years 2005 - 2010

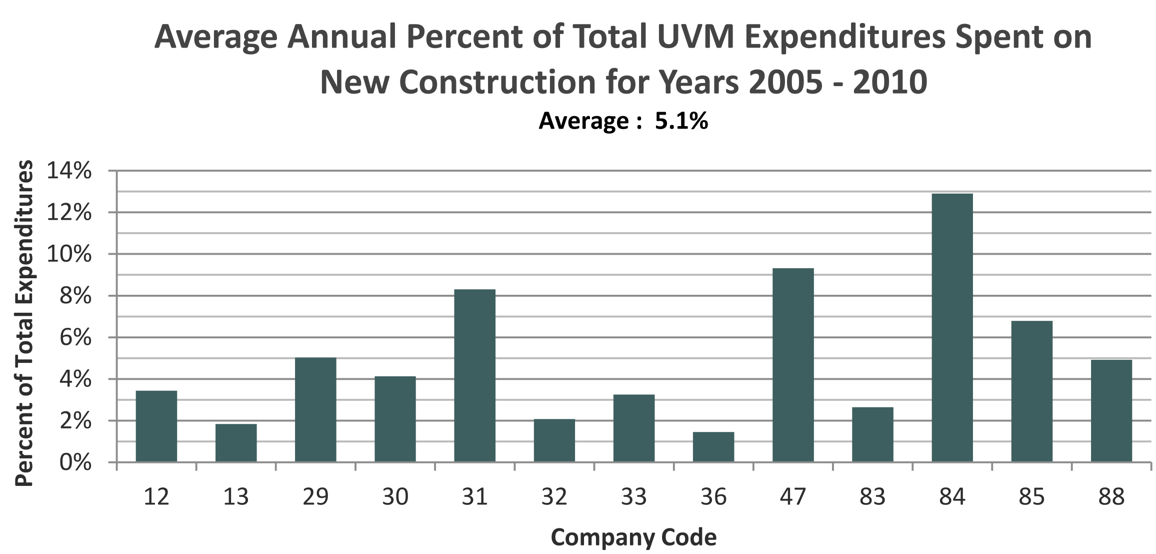

Figure 114: Average Annual Percent of Total UVM Expenditures Spent on New Construction for Years 2005 - 2010

Comments on New Construction UVM

Data Collected from responses to **Question#107**

Comments on New Construction UVM
These costs are not included in the vegetation budget.
Don't separate construction costs from storm work and unplanned or reactive work.
No Data
Those actual hours are entrepreneur's hours only.
No new construction of overhead lines

Figure 115: Comments on New Construction UVM

CAPITALIZATION OF NEW CONSTRUCTION PROJECTS

Question #109: Are your New Construction costs capitalized and funded under a different department than UVM?

100% of the respondents answered **YES**

Comments on Capitalization of New Construction Projects
The projects are budgeted by Professional Engineers
Vegetation management associated with new construction is justified using the business case to support the plant expansion, and vegetation activities are charged and capitalized as a part of that project.
Any rebuilds, which is not new construction, is capitalized including when UVM is required.
Monies are allocated through a blanket CR to designate where the dollars are charged. i.e. special projects to specific cr's.

Figure 116: Comments on Capitalization of New Construction Projects

DISTRIBUTION UVM PROGRAM ATTRIBUTES

UVM CYCLE DEFINITIONS

Question #111: Which of the following best describes your definition of your UVM CYCLE? NOTE: These definitions are taken from industry standards and previous survey responses to this question.

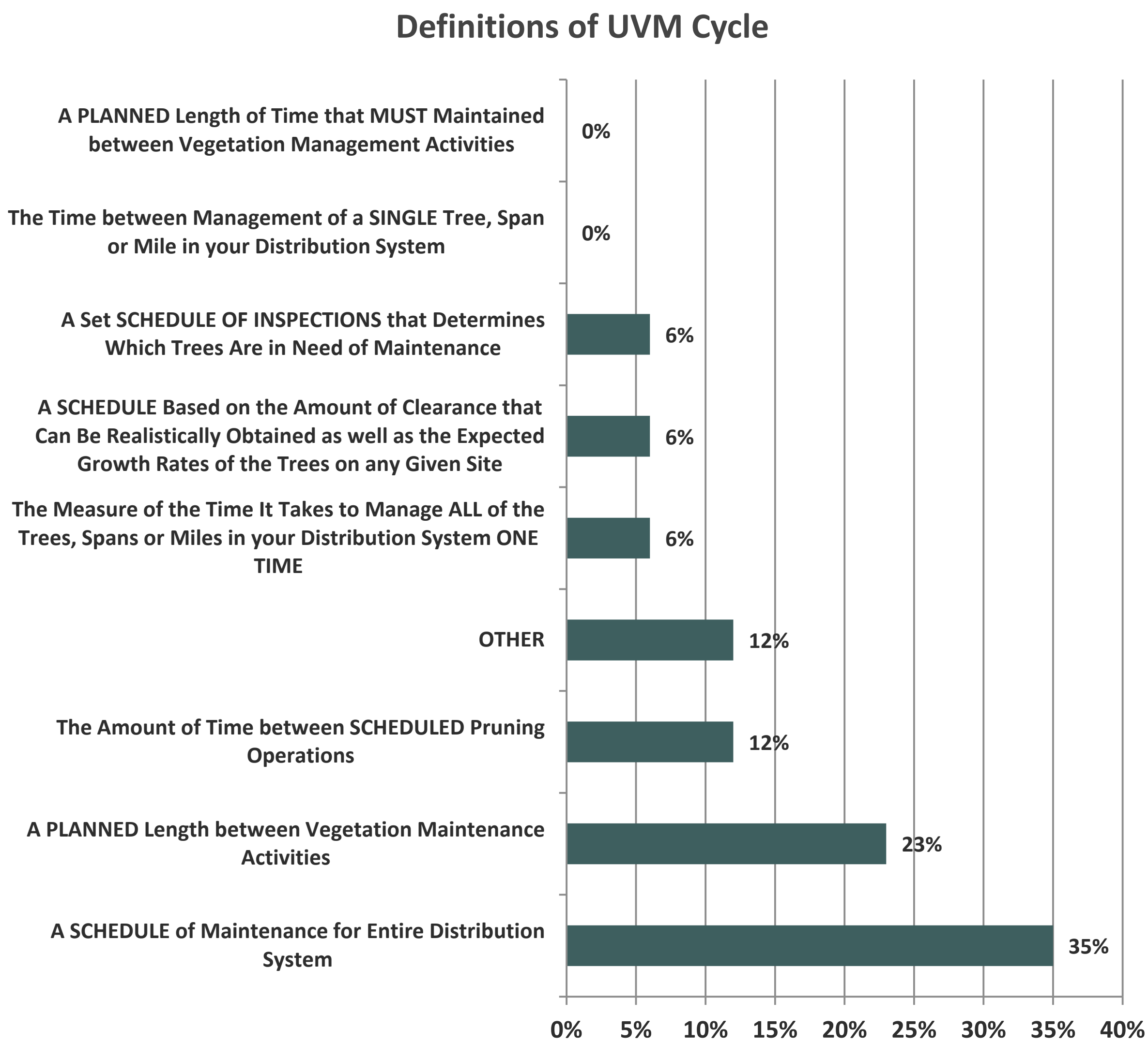

Figure 117: Definitions of UVM Cycle

Comments on and Explanations of "Other" Definitions of Cycle
Reliability Based Schedule.
We manage vegetation to a cycle
The time scheduled is not being met
Utility vegetation cycles are planned lengths of time attributed to every circuit of our system and are based on vegetation response to all factors influencing growth as well as customer density. These cycles should be maintained for each programmed interventions.

Figure 118: Comments and Explanations of "Other" Definitions of Cycle

USE OF CYCLES FOR DISTRIBUTION UVM SCHEDULING

Question #112:

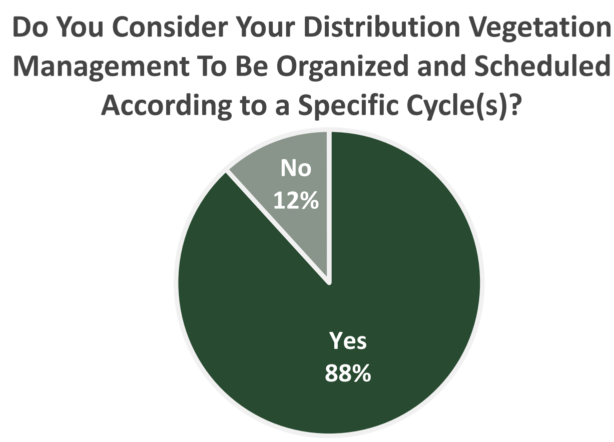

Figure 119: Use of Cycles for Organization and Scheduling

EFFECT OF BUDGET ON UVM PROGRAM SCHEDULING

Question #113:

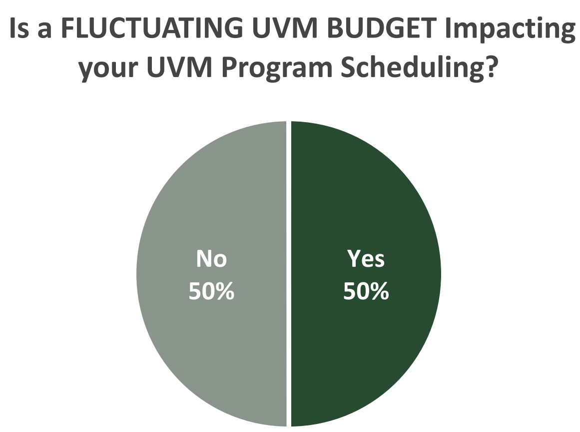

Figure 120: Fluctuating Budget Impacting Distribution UVM Program Scheduling

Comments on Budget Affecting UVM Scheduling
However, storm cost and low revenue years impact resources. [No]
The availability of both resources and budget are equal concerns.
No, because the budget does not fluctuate, it is either too small of a budget or the contract crews are too slow. We are behind the schedule due to this. [No]
Our cycles are based on vegetation response to all factors influencing growth as well as customer density. These cycles should be maintained for each programmed interventions. They can be considered as objectives. Availability of resources impacted directly our scheduling. [Yes]

Figure 121: Comments on Budget Affecting UVM Scheduling

CYCLE LENGTH REQUIRED BY PUBLIC UTILITY OR STATE BOARDS

Question #114:

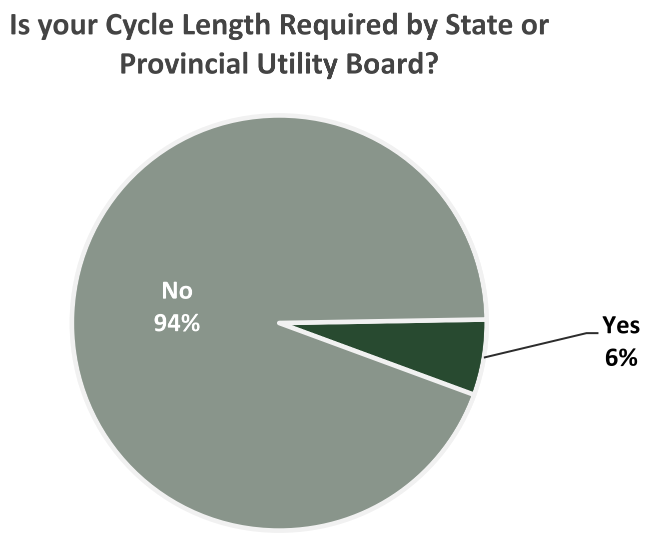

Figure 122: Cycle Length Required by PUC or State Board

Description of Rule Requiring Circuit Length and Comments
State PUC agreement requires 5 year minimum cycle.
But, we have to submit our needs in resources. Our UVM budget is authorized by our provincial energy board. (This utility responded to the question with "No")
No, for a majority of our service area, but some networks do fall under some City requirements such as the City of [ ]. (This utility responded to the question with "No")

Figure 123: Comments on and Description of Rule Requiring Circuit Length and Comments

CYCLE LENGTH AND PRE-INSPECTIONS

Question #115: If you prescribe work by inspections, do your inspections determine your cycle length or does your scheduled maintenance cycle determine the time of inspections? NOTE: An example of INSPECTIONS DETERMINING CYCLE LENGTH would be if you frequently perform system-wide inspections that identify and prescribe work only for trees that will require maintenance before the next scheduled inspection. An example of SCHEDULED MAINTENANCE CYCLE DETERMINING THE TIME OF INSPECTIONS would be inspections performed on regularly scheduled maintenance to plan and prescribe the amount of work necessary to last until the next cycle of maintenance. Depending on the length of the cycle, this would include trees that do not currently require maintenance.

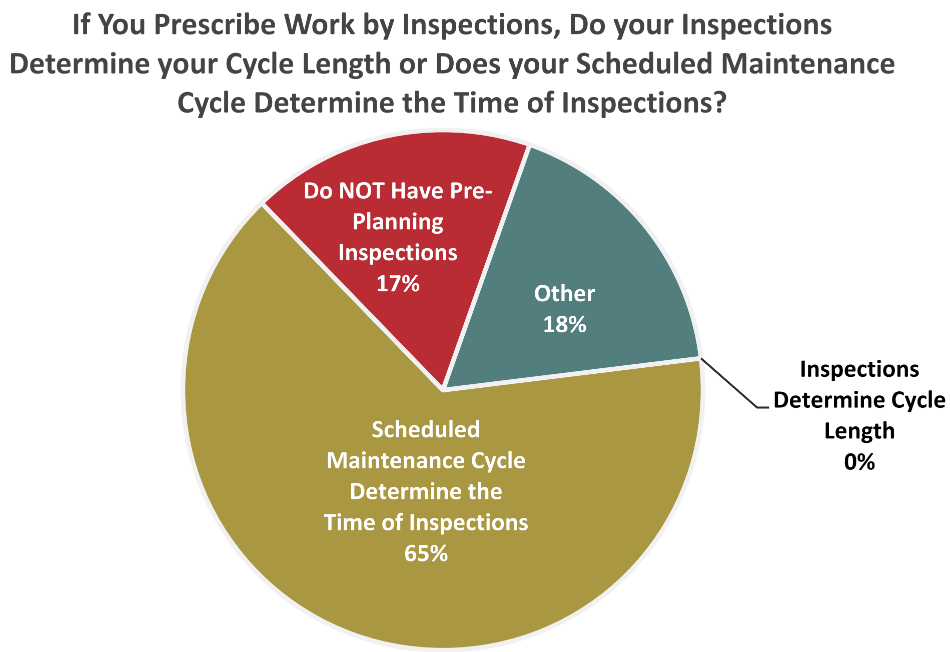

Figure 124: Do Pre-Inspections Determine Your Cycle Length?

Comments on Pre-Inspections Determining Cycle Length
Current cycle maintenance is not pre-planned; however, [Utility] has a Mid Cycle Program, where our 12-18 months maintenance cycle determines the time of inspections. [Utility] does have a Palm Cycle Program where inspections determine cycle for high risk, un-maintainable palm trees - this is 6 months or less. [Other]
Both, when feeders become due they are reviewed for needs and planned accordingly. Constant needs review are paramount to the success of our program. [Other]
...and those inspections are used to point and count spans that must be done and to qualify those due spans, ex.: on road, off-road and vegetation density. It's a work load inventory. [Scheduled Maintenance Cycle Determine the Time of Inspections]

Figure 125: Comments on Pre-Inspections Determining Cycle Length

DISTRIBUTION UVM SCHEDULING CRITERIA

Scheduling by Regions

Question #116:

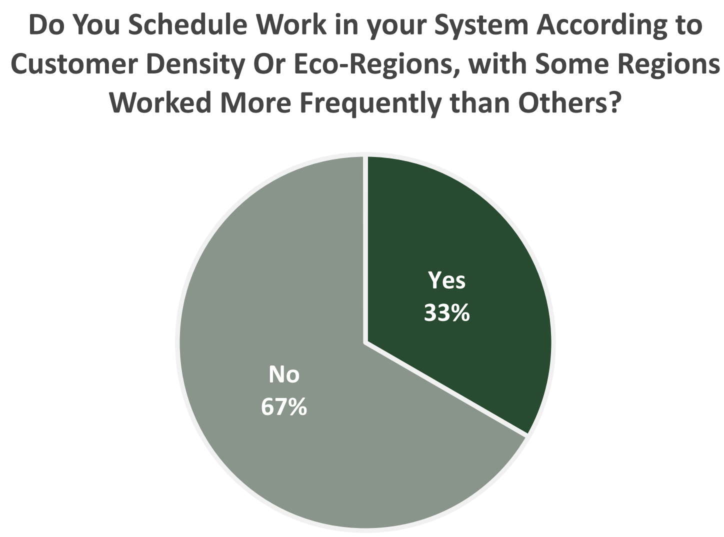

Figure 126: Scheduling According to Customer Density or Eco-Regions

List of Scheduling Regions and their Cycle Lengths
Higher tree density/high growth rates = 3 years. Lower tree density/slower growth rates = 4-5 years.
We have 4 separate Regions and they have all have a mix of cycle lengths from every 2 years to every 8 years.
Subtropical - Inspected for palms every 3 to 6 months. Everything else inspected yearly.
Northern [Region] - 8 year cycle Southern and Eastern [Region] - 6 year cycle Select urban areas - 4 year cycle.
All work is done by yearly cycles, not growth rates.
SUBURBAN: 5+ YEARS RURAL: 10+ YEARS
Suburban 42 - 48 months; urban 36 [months]
Yes, we schedule accordingly to customer density and eco-region. South-west (which includes metropolitan): 3 [years], Center: 4 [years] and East & North: 5 years.
Mountains: 4-7 years; Oak-Pine: 3-7 years; Suburban-urban: 2-5 years

Figure 127: List Scheduling Regions and their Cycle Lengths

Scheduling Influenced by Reliability Data

Question #117:

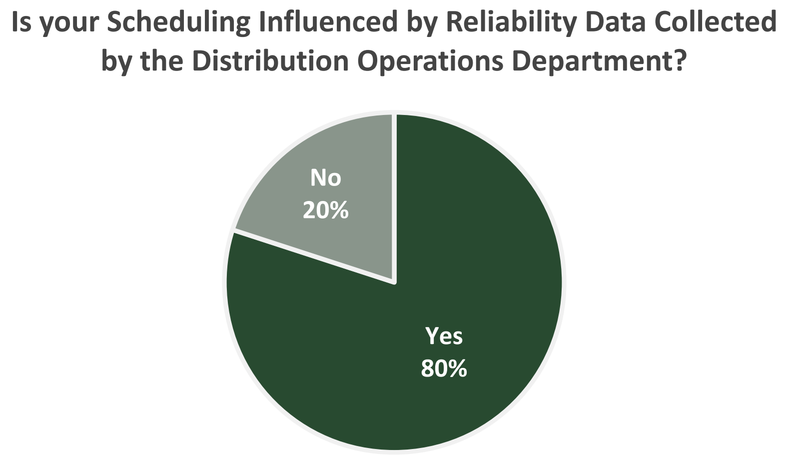

Figure 128: Is UVM Scheduling Influenced by Reliability Data?

Explanations How Reliability Measurements Influences UVM Scheduling
Circuits experiencing more frequent outages are prioritized ahead of others.
CAIDI per circuit, highest number get more VM.
If find worst performing feeders, will re-prioritize them into the schedule.
Lateral priority is determined by a 2 score, using metrics below: CI CEMI 3; CEMM 35; L-bar Momentaries. [Utility] is working to achieve a six year average cycle; however, based on performance, some circuits will be older and some will be younger.
Outage frequency, severity and trending are included in our prioritization model.
Some planned cycles are pushed back to get to areas that have a faster growth rate, or....customer complaints.
Tree Related SAIDI numbers are monitored monthly. It helps to determine where outages are occurring and, therefore, where work may be needed. Long term trends are analyzed in order to justify current funding levels.
If a section of line or circuit is experiencing an unacceptable amount of outages we will trim out area before the designated UVM cycle.
From reliability data and requests from engineering.
[Only] for the tree removal program.
Poorly performing line segments are priority for line clearance.
People who have re-occurring outages are taken into account.
All circuits/feeders reliability is monitored throughout the year for vegetation outages. Circuits with poor performing reliability #'s are inspected and if it determined by the Forester/OC that the circuit is performing badly due to grow-in type vegetation outages, then the circuit will be added to the trim list for that coming year.

Figure 129: Comments on and Explanations of How Reliability Measurements Influences UVM Scheduling

Regulatory Requirements for Addressing Worst Performing Circuits

Question #118:

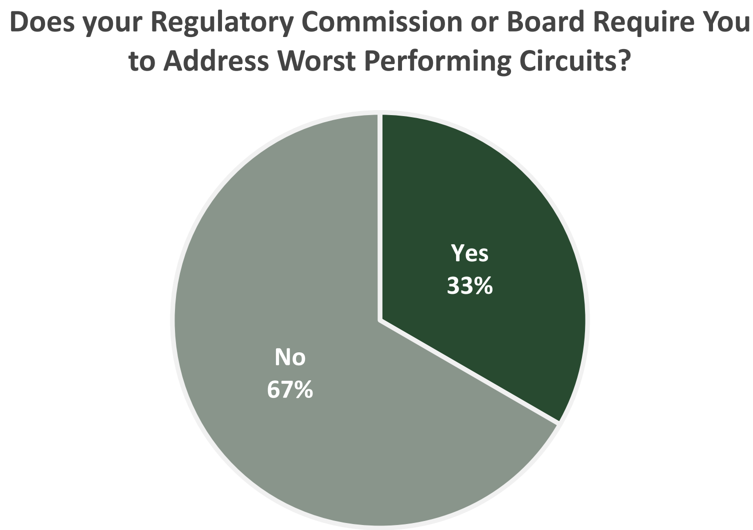

Figure 130: Regulatory Boards Requiring that Worst Performing Circuits Be Addressed

Comments on and Explanations of UVM Reliability Requirements
Top 10% of lowest performing circuits cannot appear in the top ten two years in a row. [Yes]
We have reliability targets that the Board expects to be achieved. [Yes]
Drive out circuit and trim out concerned areas. [Yes]
Each jurisdiction within our company does put out its Targeted Circuit lists yearly. If a circuit on the Targeted Circuit list is there due to vegetation concerns, then it is looked at and any work needed to mitigate the problems are remedied. This is accomplished by the first half of the year or by June 30th each year. [No]
Improving reliability performance on the worst performing circuits is important to AEP's veg program but it must be addressed and completed. [Yes]
Any key customer issues can require us to work that area out of our normal trim cycle. [Yes]

Figure 131: Comments on and Explanations of UVM Reliability Requirements

CLEARANCE REQUIREMENTS

UVM Program Clearance Requirements and Regulatory Oversight

Question #119: Does your Distribution UVM program have any of the following specific clearance requirements? NOTE: For each clearance situation (e.g. distance below primary, distance above primary, distance to side of primary), please describe the clearance requirement in inches or centimeters. The second column is clearance required at all times, 24 hours a day, 7 days a week.

UVM Program Clearance Distance Requirements

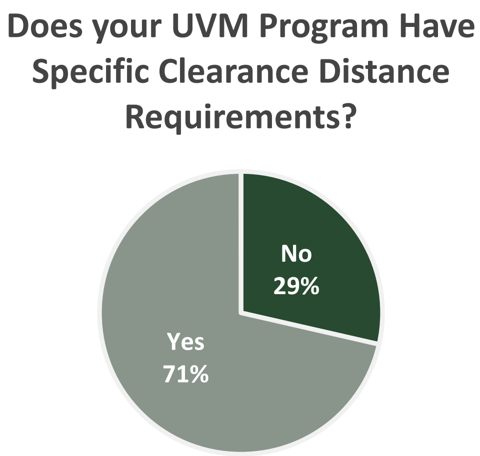

Figure 132: Does your UVM Program Have Specific Clearance Distance Requirements?

Clearance Distances Required at Time of Maintenance

Clearance Distance Required at Time of Maintenance in Inches			
Company Code	Distance Below Primary	Distance Above Primary	Distance to Side of Primary
3	Equal to the Ground	195	195 for Deciduous 120 for Conifer
27	168	120	144
29	120	180	120
30	180	240	180
41	48	48	48
47	138	120	195
88	84	84	84
90	120	120	120
91	72	72	36

Figure 133: Clearance Distance Required at Time of Maintenance in Inches

Clearance Distances Required at All Times

Data was collected from **Question #119**

Required Clearance Distance 24/7 in Inches			
Company Code	Distance Below Primary	Distance Above Primary	Distance to Side of Primary
12	12	12	12
27	18/48 Multiple State: Requirements Vary Fire Season Requirements	18/48 Multiple State: Requirements Vary Fire Season Requirements	18/48 Multiple State: Requirements Vary Fire Season Requirements
30	24	48	24
41	18/48 Two Different Requirements Fire Season Requirements	18/48 Two Different Requirements Fire Season Requirements	18/48 Two Different Requirements Fire Season Requirements

Figure 134: Required Clearance Distance 24/7 in Inches

Comments: Regulatory Influences on Clearance Distance Requirements

Are your clearance requirements influenced by regulatory requirements?
No. [Company has Clearance Requirements]
There are two laws governing tree clearances in [State]. Listed above is the year-round requirement issued by the [State] Public Utilities Commission. We also have regulations under the [State] Public Resources Code that requires 48 inches of 24/7 clearance during fire season.
Varies per state, per growth rate of vegetation and regional public resource codes and line configuration, voltage and during fire season. [States] - 18in - 4ft all (driven by local fire dept). [State] - Regular clearance 24/7.
Distance requirements at the time of maintenance based on cycle length and ecological factors. Specific distances vary from tree to tree and are at the discretion of our qualified utility arborists.
No, these are the desired results
The clearance required at time of maintenance is for three years of clearance dependent on species.
No requirements.
15 feet is our requirement.
Not at all. [Has clearance requirements]
Single phase requirements: 10 foot, 3-phase requires 15 foot and 46 kV sub-transmission requires 25 foot clearance.

Figure 135: Comments on "Are your clearance requirements influenced by regulatory requirements?"

Clearance Duration Requirements

Distribution UVM Program Clearance Duration Requirements at Present

Question #120: Does your Distribution UVM program require specific clearances to primary voltages that will last for a specified cycle length?

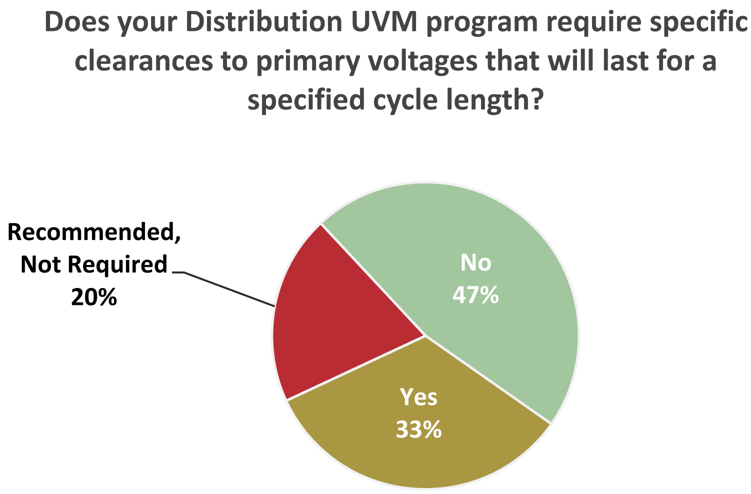

Figure 136: Does your Distribution UVM Program Have Clearance Duration Requirements?

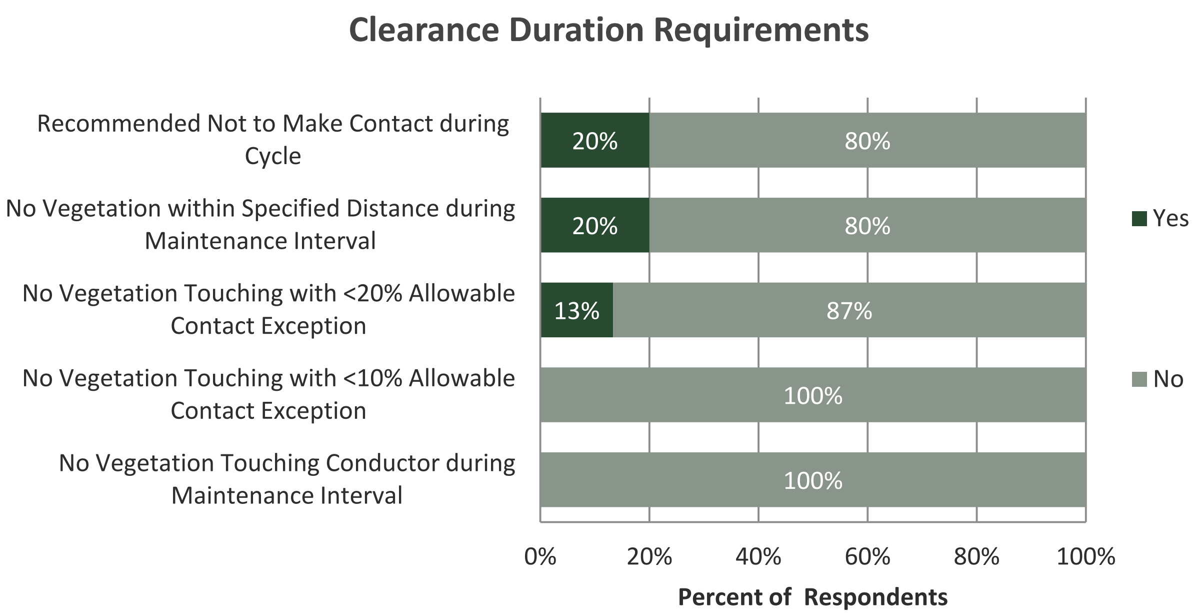

Figure 137: Clearance Duration Requirements

Comments on Clearance Duration Requirements

Data was collected from **Question #120**

Comments on Clearance Duration Requirements
Clearance depends on species growth rates and cycle length. Specific clearances are not dictated to the crews. [No]
No multiple cycle lengths. [Did not answer]
Our quality assurance program has verified that no trees are within the mandated clearances 99.79% of the time. [No]
[Utility] - no exceptions - must maintain clearance year around. Also, maintenance cycle length in years is 2-4 and inspection cycle is also 2-4 years. [Yes]
Our average cycle length on our system is 4 years. [Recommended]
Clearance holds expected duration 92% of the time. [Yes]
Although our cycle varies, due to funding and resource restrictions, we have found it challenging to meet our planned cycle targets. Our current target average cycle length is 8. [Yes]
We have a poor record of attaining 4 year cycle. [No]
We have 2- planned cycle lengths. 1-for suburban (5-years) and the other for rural (ten year cycle). [No]
Our expectations is that the clearance be 15 feet and last the cycle. [Recommended]
The 4 year cycle length is average for a very large territory. [Yes]
Trees shall be trimmed as to provide a maximum clearance from primary conductors. Unless otherwise indicated by a designated company representative, all trees at a minimum shall be trimmed back to the previous trim point (amount of clearance obtained during the last trim, including previous sky-trims) or as per our clearance table, whichever is greater. We do take into account seasonal growing patterns during wet seasons which would cause some circuits to reach the conductors quicker than anticipated. [Recommended]

Figure 138: Comments on Clearance Duration Requirements

Desired Clearance Duration Requirements

QUESTION #121: If you don't require sufficient clearance distance for a specific cycle length, but would like to, how would you apply it to your system, using the parameters provided?

NOTE: If you have another preferred method for specifying clearance duration, please express it in the comment field.

Desired Clearance Duration Requirements

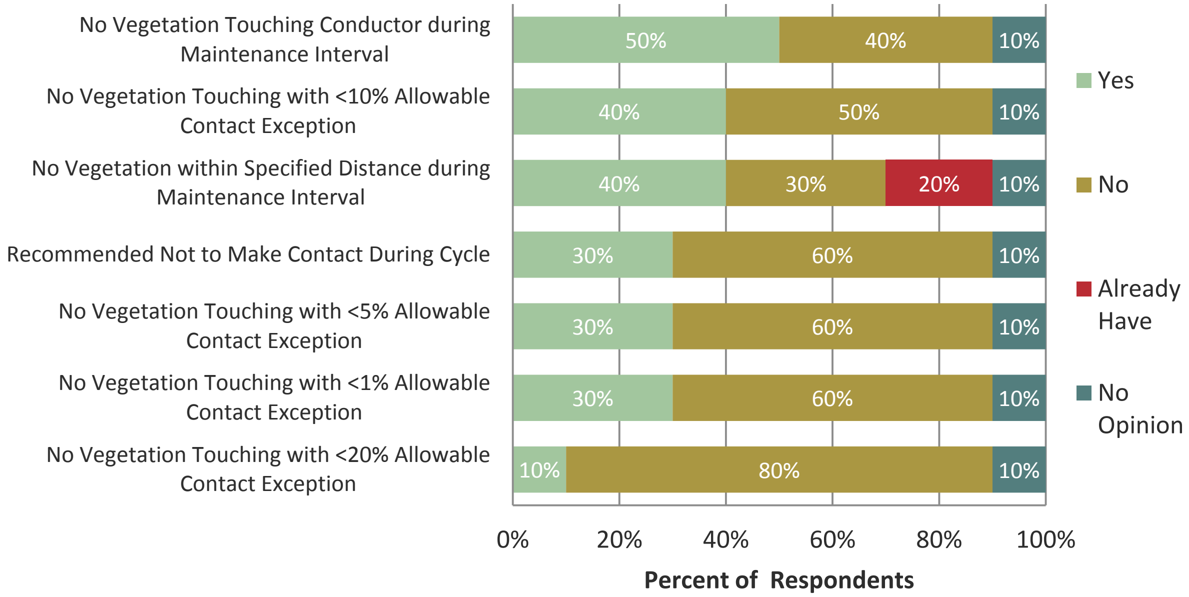

Figure 139: Desired Clearance Duration Requirement

Some companies gave several options for desired clearance duration requirements. The redundancy could have been due to different environmental regions requiring different handling of the vegetation or the attitude that several of the options would be desirable versus having no requirements or recommendations. The cycle for clearance duration ranged from 1 – 6 years, with two and four year durations being the predominant target length.

Data was collected from **Question #121**

Comments on Desired Clearance Duration Requirements
No proposed minimum separation.
We estimate our average tree is pruned every 4-5 years but every tree location is unique, fast growing vs. slow growing; heritage tree vs. weed; environmentally sensitive area vs. non-environmental area, customer issues, etc.... If you set a duration requirement you ignore these other constraints. In my view this is an impossible dream. On average one can achieve a cycle length that is meaningful but it is difficult to achieve on a tree by tree basis.
All things considered, if we could maintain a target of zero vegetation within 12 inches of the conductor with a 10% allowable contact exception, we would be in a good place.
Do not have a 4 year cycle and trees are burning regularly in all levels of the distribution circuits from secondary to 12 kV.
Cycles based on individual feeders and range from 3 - 5 years depending on location, vegetation, last time trimmed, etc.
One size does not fit the biological conditions of our system.
The ideal situation for us with regards to the "desired clearance requirements" is to have absolutely no trees around or under the feeder. The "property owner" should not have the right to have trees which can impact our distribution network. As a . . . Distribution Utility we- in essence - send $ 70 million annually to the "chippers", enough money to refurbish all of our high schools.
This concept would be unfair to most tree trimming contractors on our Utility since our contracts only run 2 years. Many times during the contract process new contractors are awarded this work and weren't responsible for the last trim cycle which would make this concept hard to police.
We have a two year cycle and try to maintain that clearance when trimming.

Figure 140: Comments on Desired Clearance Duration Requirements

Clearance Duration Requirements and Over-all Program Safety

Question #122:

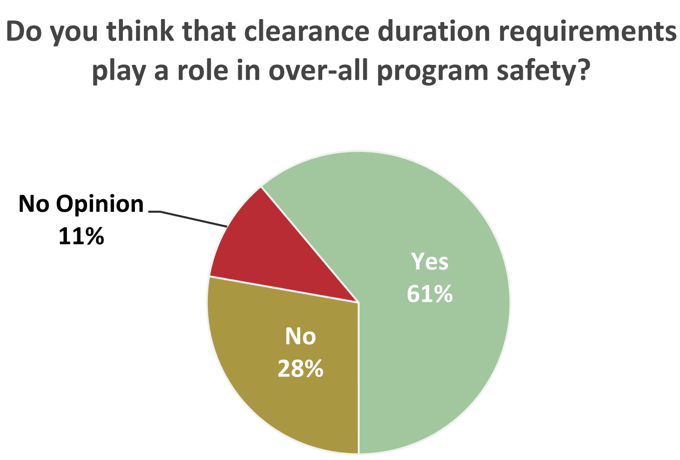

Figure 141: Clearance Requirements and Over-all Program Safety

Data was collected from **Question #122**

Comments on Clearance Requirements' Role in Program Safety
If limbs are allowed to make contact, each of those trees is now considered "energized" by OSHA. [Yes]
On single phase, we assess each tree for the likelihood of it causing an outage. Therefore some tree-to-conductor clearances are closer to the energized conductor. [Yes]
Potential for violating minimum approach distance. [Yes]
We maintain clearance from vegetation to conductors primarily for public and worker safety. [Yes]
Due to the organic nature of vegetation a time based requirement adds a lot of ambiguity and uncertainty into the maintenance standards. If over-all program safety is the goal, a distance based requirement would serve the purpose more effectively. [No]
In the presence of clearance duration requirements, an argument can be made that safety will be enhanced because clearance will be maintained for certain lengths of time. Providing assurance of certain levels of clearance means safer work environment for workers and the general public. [Yes]
It's too dependent on time and not growing conditions through cycle. [No]
We are not familiar with that kind of requirement. [No Opinion]

Figure 142: Comments on Clearance Requirements' Role in Program Safety

DISTRIBUTION UVM SCHEDULING CYCLES

System-Wide Standard Cycle Lengths

Meeting Targets for System-Wide Standard Cycle Length

Question #123:

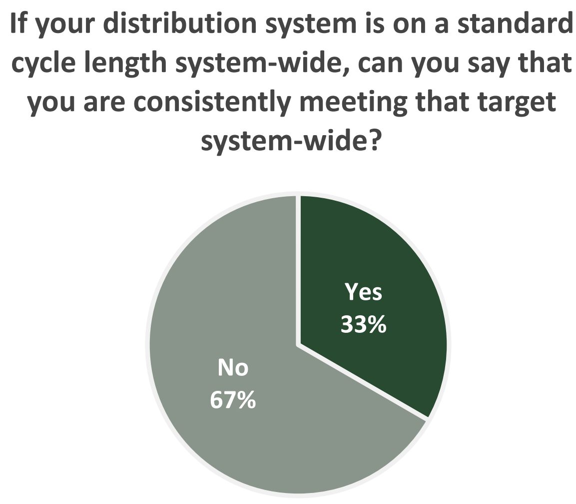

Figure 143: Percent of Companies Meeting Targets for System-Wide Standard Cycle Length

Data was collected from **Question #123**

Comments on Not Meeting Targets for System-Wide Standard Cycle Length
Seeking to designate more resources to get back on cycle.
Not on standard cycle system wide.
Due to budget and issues with compliance to standards, we do have an accumulated backlog of work.
For Feeders only. [Utility] is working toward a 6 year average Lateral cycle.
We currently have about 25% of our system as overdue maintenance according to our cycle length target. As we continue to build a stronger rate case to secure more vegetation management funding, we are trying to mitigate risk through improved program planning and development. This includes investing in advanced analytics to help prioritize and focus of VM funding and the implementation of new programs focused on addressing incremental risk caused by overdue maintenance.
Not a chance.
Because we do not know the vegetation density of each span and the type of work is required, our miles of line fluctuate. Our budget does not reflect the work load. We bring in specialized equipment to reduce our labor cost so to increase line mileage completed.
Clearances obtained, rights, growth and weather.
But it is an objective. We ask our energy board for more resources. We try to prescribe clearing instead of trimming.
This has happened twice in the past 6 years where cycle targets were not met due to budget reductions. We still target the worst performing feeders and the goal is the better performing feeders next trim cycle can be extended a year or two to make up for this.

Figure 144: Comments on Not Meeting Targets for System-Wide Standard Cycle Length

Reasons for Not Meeting Target Cycle Lengths

Question #124: When you are NOT meeting your target cycle length, it is due to:

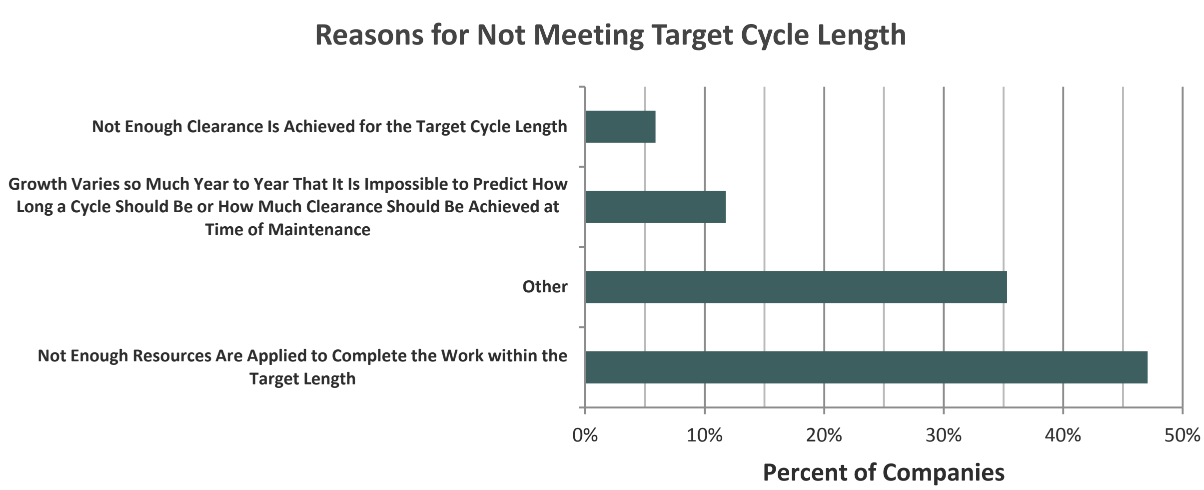

Figure 145: Reasons for Not Meeting Target Cycle Length

Data was collected from **Question #124**

Comments on Reasons for Not Meeting Target Cycle Length
No cycle. [Answered, "Other"]
Also when inadequate funding is available. [Answered, "Growth Varies"]
Due to palms and fast growing species for which we are unable to obtain proper clearance. [Answered, "Not enough clearance"]
Not enough resources and the resources that we have are not productive enough. [Answered, "Other"]
Budget inadequate. [Answered, Not enough funds'']
Budgets. [Answered, "Other"]
We recently obtained new resources to do more work, and we are on the way to meet our target cycle. [Answered, "Other"]
Budget Dollar allocation for Vegetation O&M work is the biggest factor. We have conducted growth studies and our preferred cycle targets are known for all our areas. If we are allocated adequate budget dollars then, in most cases, preferred cycle targets are achieved. But if budget cuts are made, we normally do not meet our cycle target. [Answered, "Other"]
Cycle length is met. [Answered, "Other"]

Figure 146: Comments on Reasons for Not Meeting Target Cycle Length

DEFINITIONS OF UNITS OF WORK

Definition of a Tree

Question #130: How do you define the following units of work?

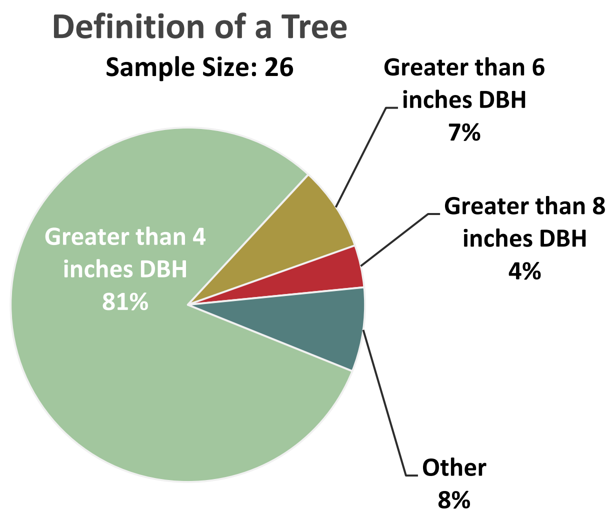

Figure 147: Definition of a Tree

Other Definitions for Trees
Do not define dbh, because we are not on cycle the pruning may include all of the above.
None
We are prescriptive about each work site so the DBH may vary.

Figure 148: Other Definitions for Trees

Note: For the companies using metric vs. English measurements (cm vs. inches), the choices were 10cm, 15cm or 20cm (these closely approximate the 4, 6 or 8 inches in the English measurements).

In 2006, **65%** of utilities defined trees as greater than 4 inches.

Definition of a Brush Unit

The responses for this graph were also taken from **Question #130**.

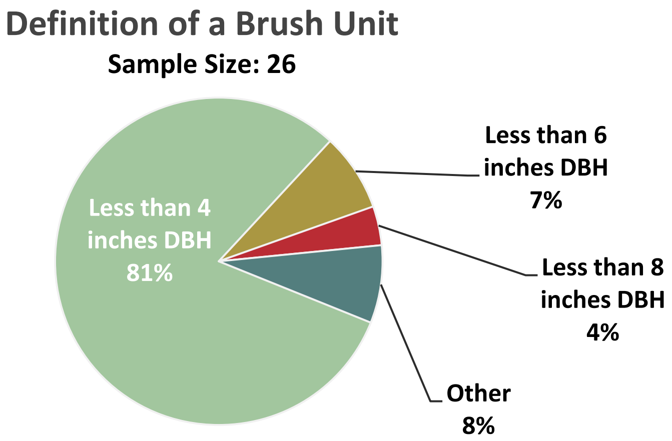

Figure 149: Definition of a Brush Unit

Other Definitions for Brush
Do not define dbh, because we are not on cycle the pruning may include all of the above.
None
We are prescriptive about each work site so the DBH may vary.

Figure 150: Other Definitions for Brush

Note: For the companies using metric vs. English measurements (cm vs. inches), the choices were 10cm, 15cm or 20cm (these closely approximate the 4, 6 or 8 inches in the English measurements).

In 2006, **62.5%** of utilities defined trees as greater than 4 inches.

TREE INVENTORIES

Tree Populations

For the purposes of this study the WORKLOAD INVENTORY is defined as the number of trees worked or managed during a complete cycle of your distribution system.

Question #131: Do you know how many trees you manage on your distribution system? NOTE: If you have counted trees for more than one complete cycle, then your workload inventory is the average number of trees worked during a complete cycle.

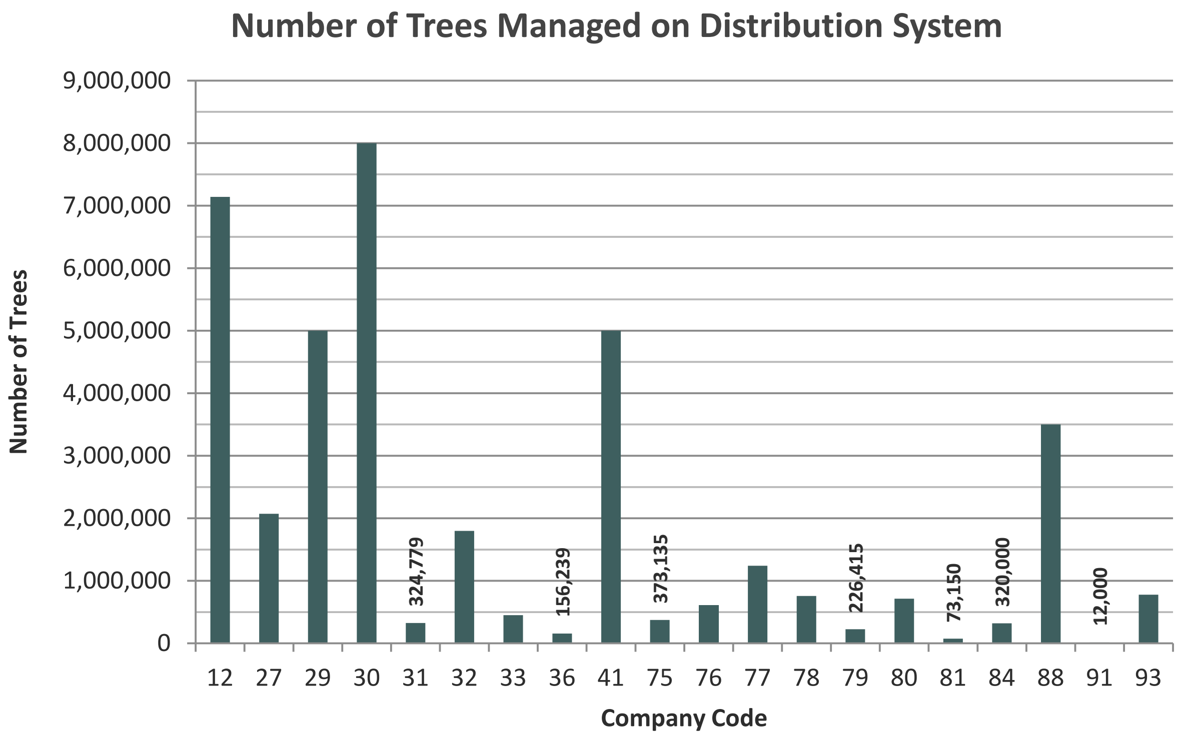

Figure 151: Number of Trees Managed for Distribution UVM

How Tree Inventories Are Determined

Question #132: Your workload inventory was determined by:

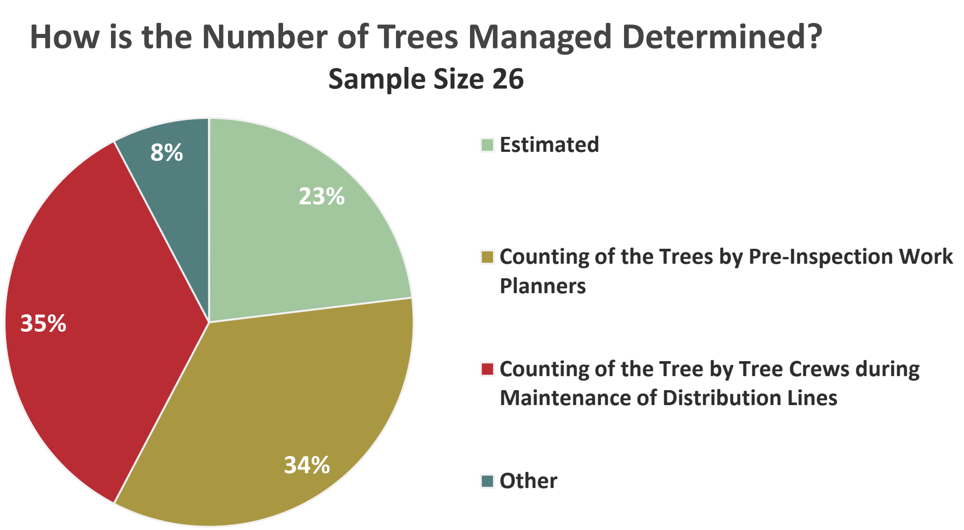

Figure 152: How is Tree Inventory Determined?

Descriptions of How Tree Inventories Are Determined
Consultant reviewed D system, sampled sections in urban, suburban, rural areas - extrapolated. [Answered: Estimated]
From [Tree Contractor] extrapolation. [Answered: Estimated]
Sample survey done by 3rd Party Vendor [Answered: Estimated]
Using our average trees treated per miles for 2009 and 2010 multiplied by our ROW miles. [Answered: Estimated]
We are now counting pruned trees and removed trees. Have not completed any cycle using this measure. [Answered: "…Counting Trees by Tree Crews …"]
Feeders are reviewed through inspection and work estimated by reviewer. [Answered: Estimated]
For trimming or brush cutting we do count spans. For us spans are the base units for work load evaluation and entrepreneur remuneration. [Answered: Other]
A tree count study was conducted years ago and no updated tree count study has been performed since, so we still use this estimation number of [ ] trees that we manage along our ROW's. [Answered: Estimated]
N/A [Do not have a tree inventory]

Figure 153: Descriptions of How Tree Inventories Are Determined

TREE TYPES

Question #133: What percent of your total managed trees in your service territory is deciduous, coniferous, palm or other?

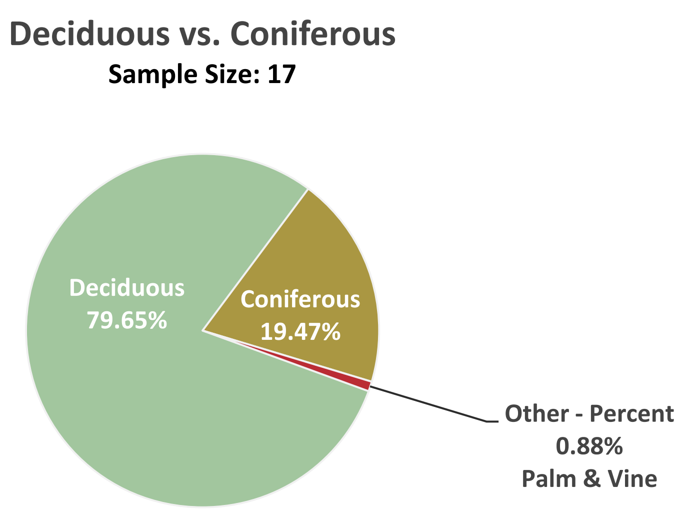

Figure 154: Deciduous vs. Coniferous

NUMBER OF NON-ROUTINE TREES TREATED ANNUALLY

Question #134: If you track the number of trees treated that are NOT routine work, such as customer requests, ticket or tag work, please supply the number treated annually?

NOTE: 'Treated' is defined as the combination of trees pruned and removed.

Number of Trees Treated = Number of Trees Removed + Number of Trees Pruned

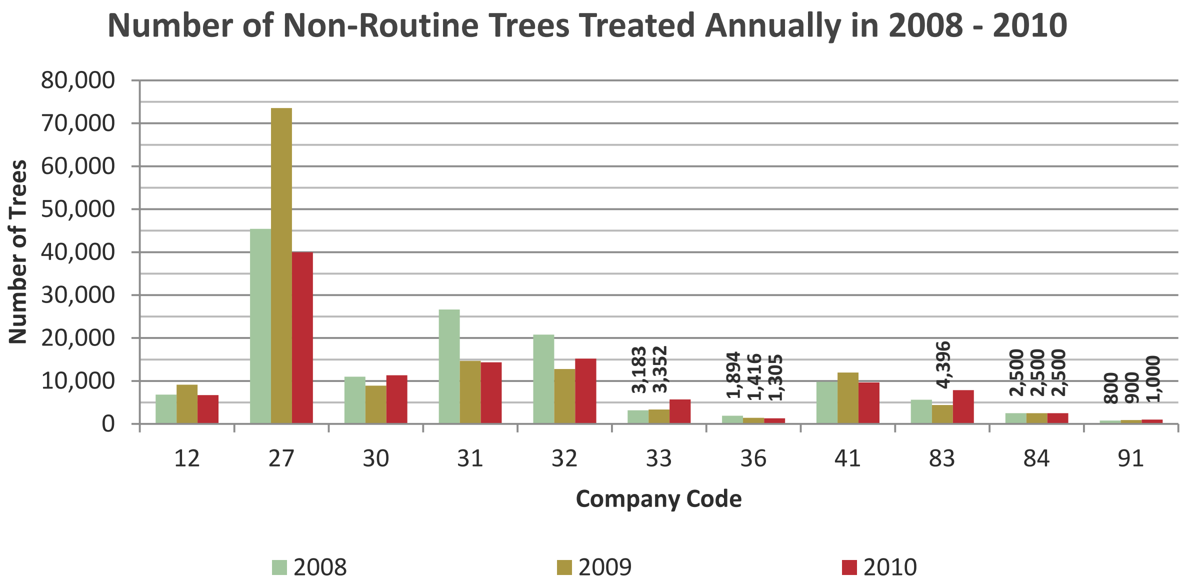

Figure 155: Number of Non-Routine Trees Treated Annually in 2008 - 2010

Statistics in following graph calculated from data collected for **Question #131** and **Question #134.**

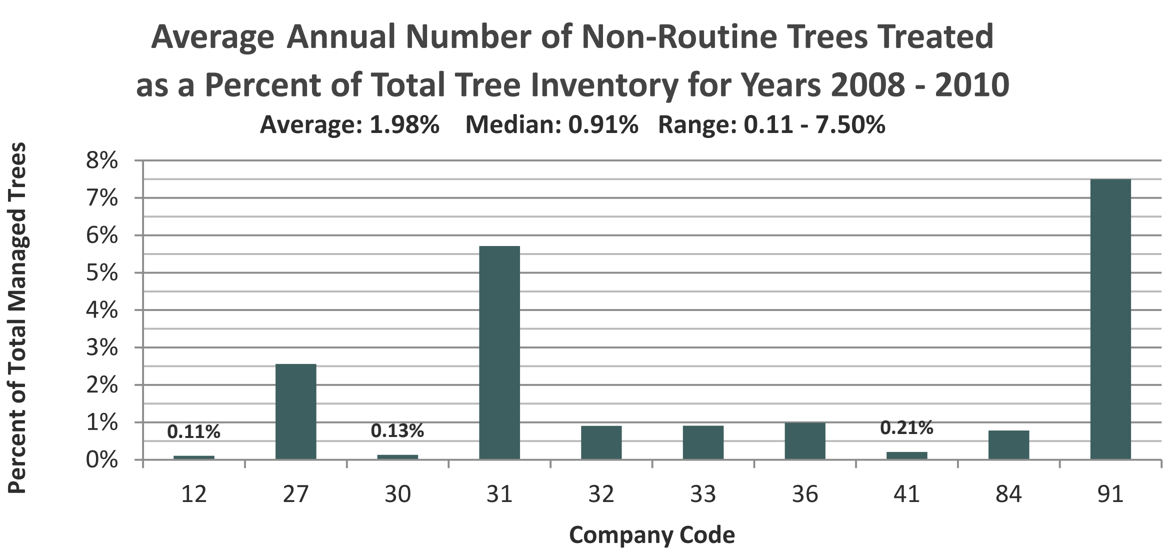

Figure 156: Average Annual Number of Non-Routine Trees Treated as a Percent of Total Tree Inventory

Note: Above graph's numbers were calculated from the average annual number of trees treated that were non-routine divided by the reported total number of managed trees on the distribution system.

CONTRACT STRUCTURES FOR DIFFERENT CATEGORIES OF WORK

Question #135: What percent in each category of work is completed under each costing structure?

The graphs for the next four categories were derived from data supplied in question #135 (above).

Contract Structure for Routine Maintenance

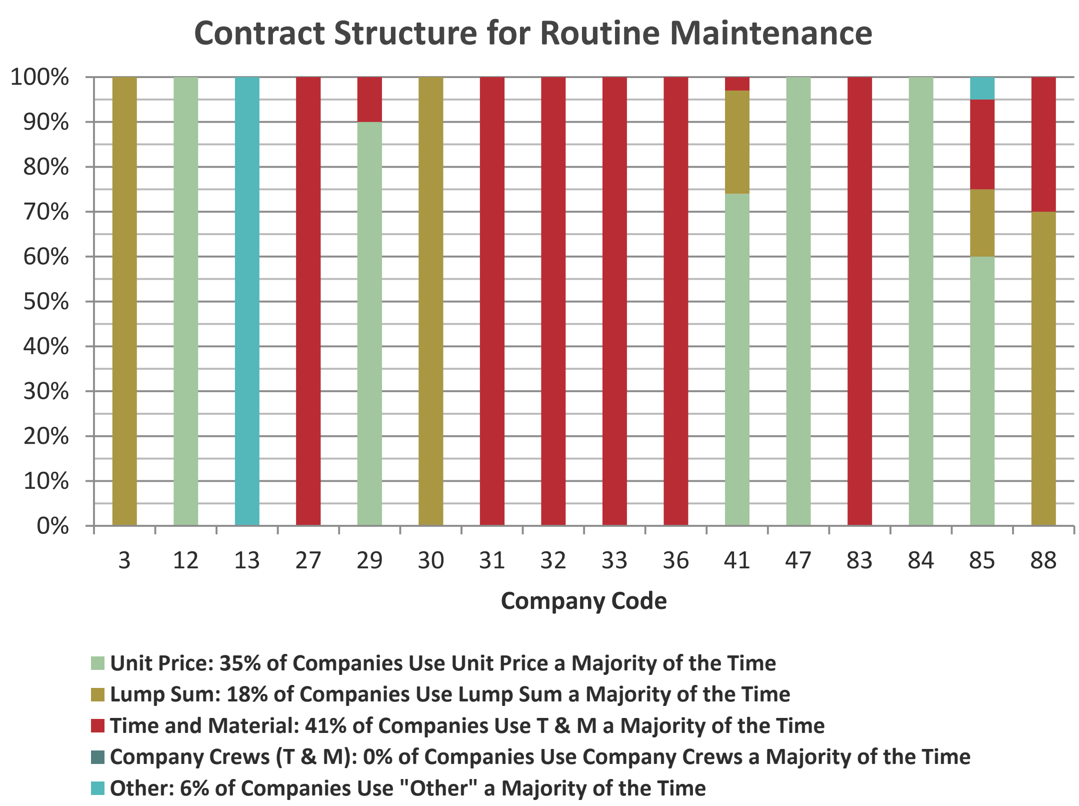

Figure 157: Contract Structure for Routine Maintenance

NOTE: The graph (above) has the percent of companies that use each contract structure a majority of the time located in the legend.

Comments on Contract Structures Used for all Tree Maintenance Categories
Other = Hourly
Our routine maintenance is completed by company crews and is planned and evaluated using a targeted unit price.
We are in a reactive mode, not a cycle mode.
For routine maintenance only, we have a bonus/penalty system that is used to incentivize/penalize contractors for their work. It is based on their cost per mile bid vs. actuals.

Figure 158: Comments on Contract Structures Used for all Tree Maintenance Categories

Contract Structure for Unplanned (Reactive) Work

Please see **Question #135** above.

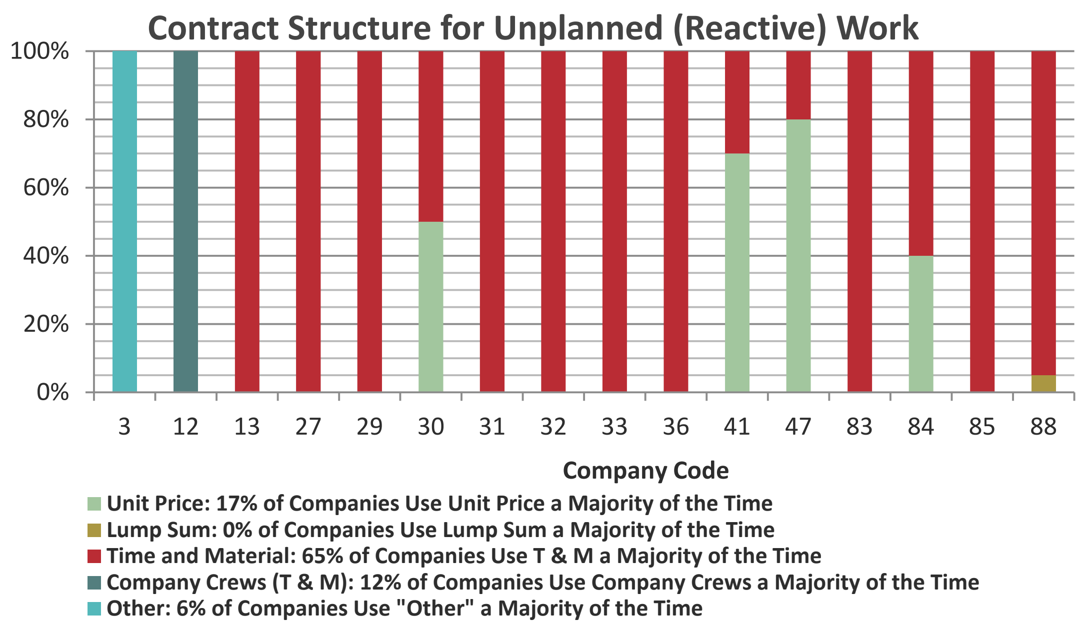

Figure 159: Contract Structure for Unplanned (Reactive) Work

NOTE: The graph (above) has the percent of companies that use each contract structure a majority of the time located in the legend.

Data collected from **Question #135** above. **NOTE:** The graphs below have the percent of companies that use each contract structure a majority of the time. The graphs also have the percent of companies that use each contract structure a majority of the time located in the legend.

Contract Structure for Emergency Work

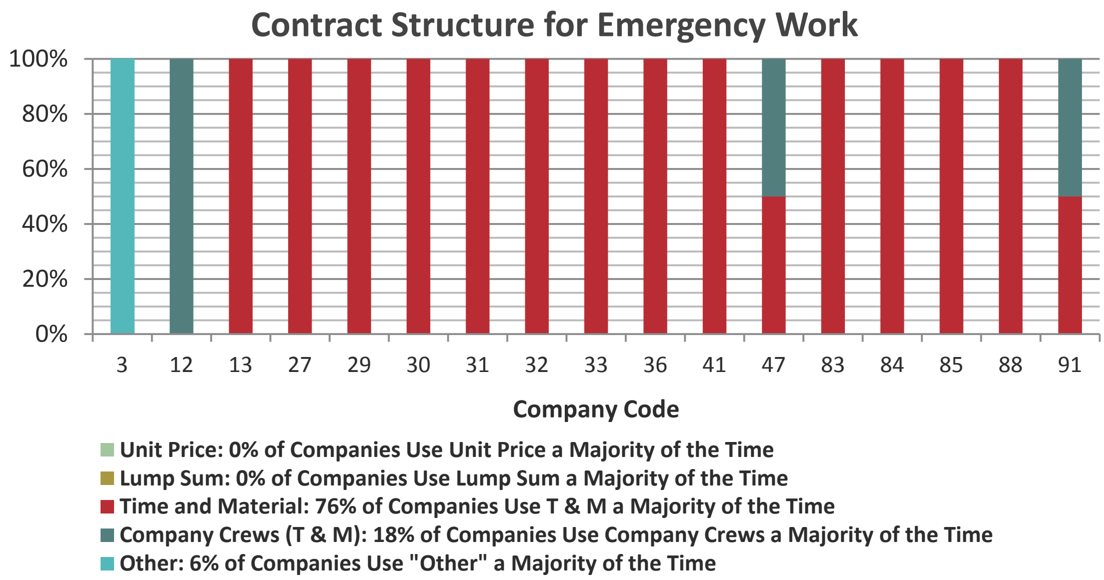

Figure 160: Contract Structure for Emergency Work

Contract Structure for Capitalized Work

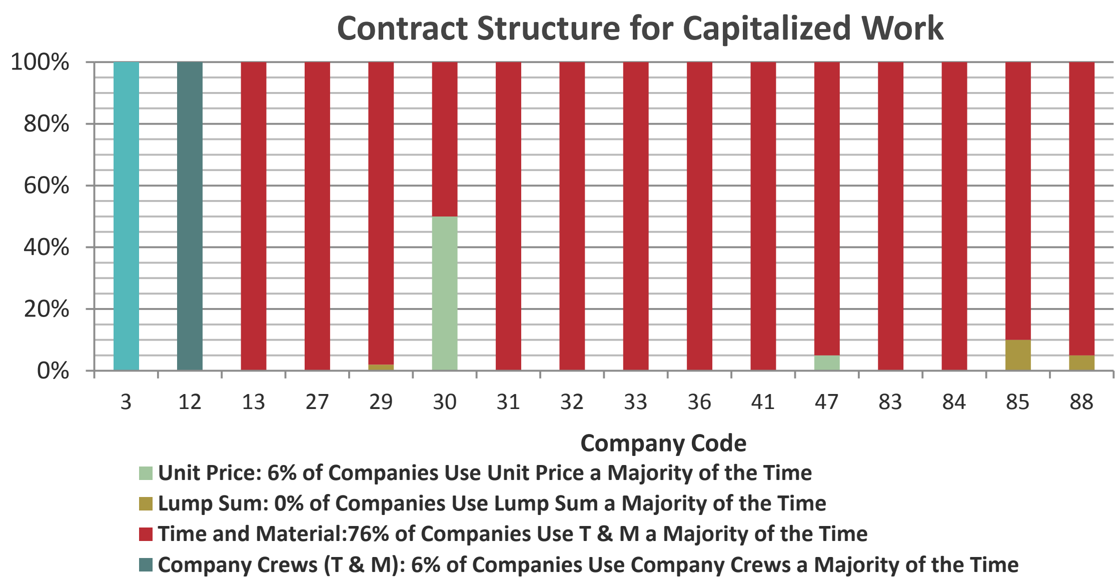

Figure 161: Contract Structure for Capitalized Work

TRACKING OF INVENTORY METRICS

Question #136: Do you track the following metrics?

NOTE: 'Treated' is defined as the combination of trees pruned and removed.

Number of Trees Treated = Number of Trees Removed + Number of Trees Pruned

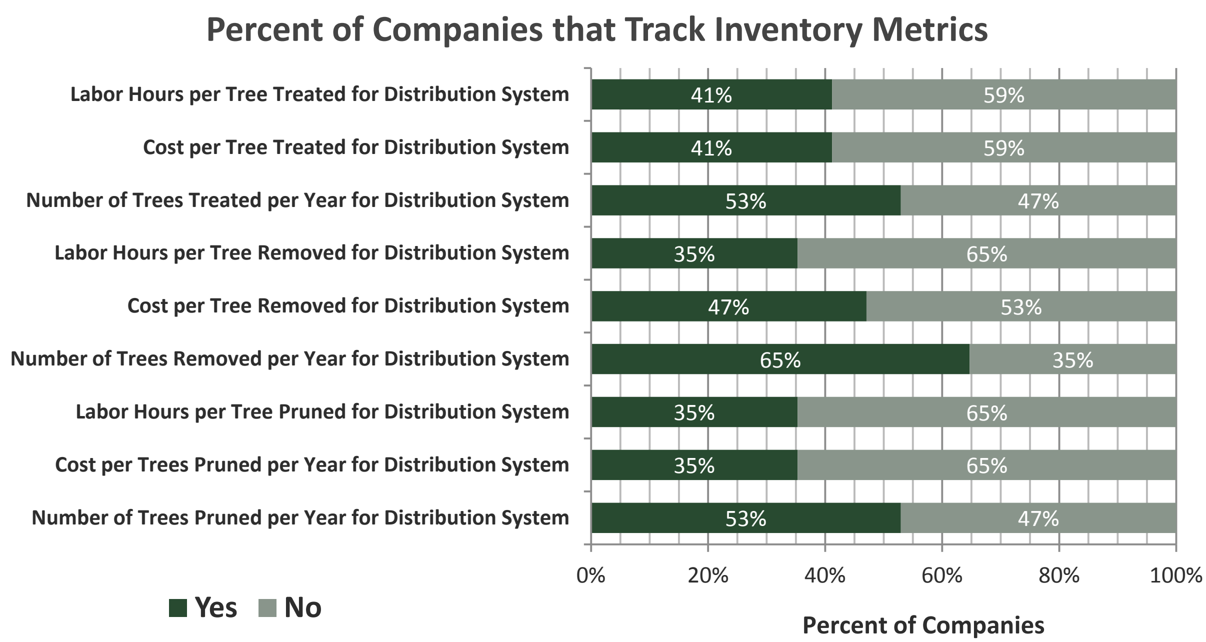

Figure 162: Percent of Companies that Track the Following Inventory Metrics

NUMBER OF TREES TREATED

Question #137: If you answered YES to any choice in the last question, provide the annual number of trees pruned, removed and treated and the corresponding cost per tree and labor hours expended per tree in the following years.

NOTE: 'Treated' is defined as the combination of trees pruned and removed.

Number of Trees Treated = Number of Trees Removed + Number of Trees Pruned

Number of Trees Pruned

Data was collected from **Question #137**

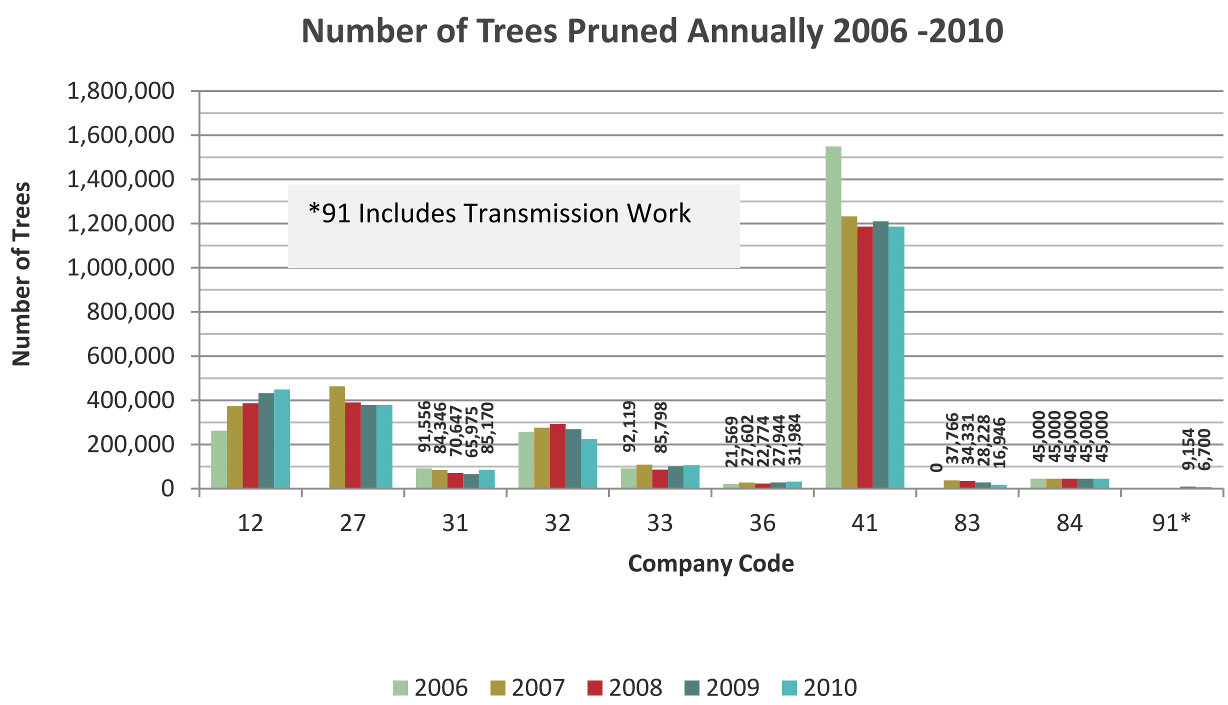

Figure 163: Number of Trees Pruned Annually 2006 -2010

Number of Trees Removed

Data was collected from **Question #137**

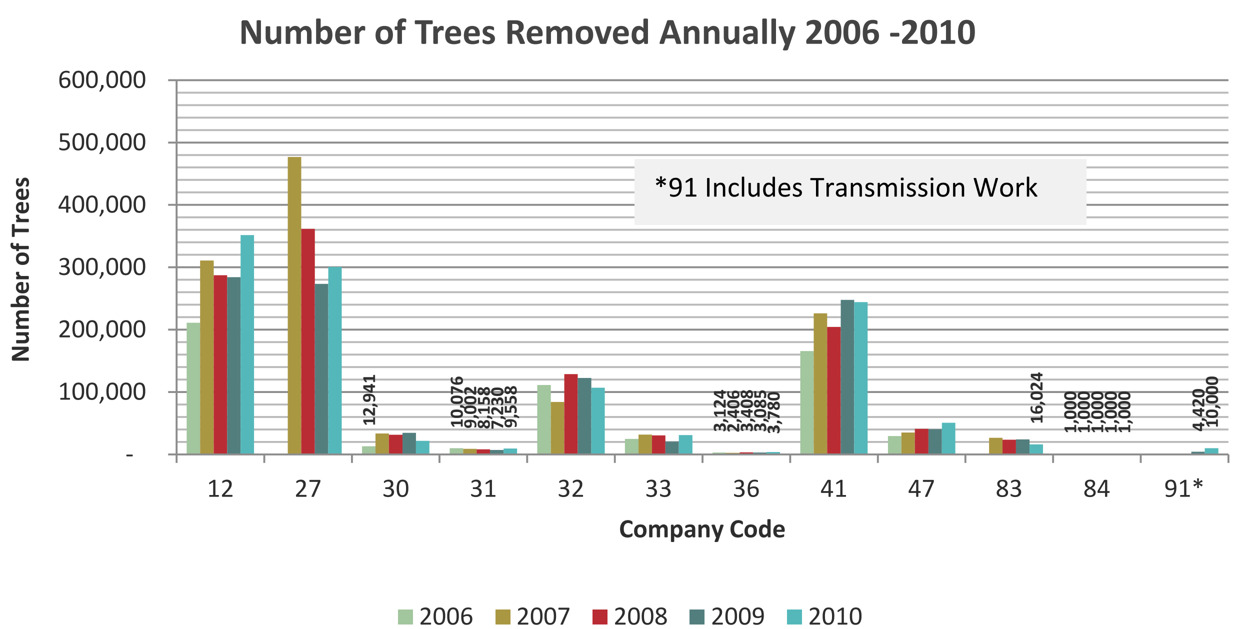

Figure 164: Number of Trees Removed Annually 2006 -2010

Number of Trees Treated

Data was collected from **Question #137**

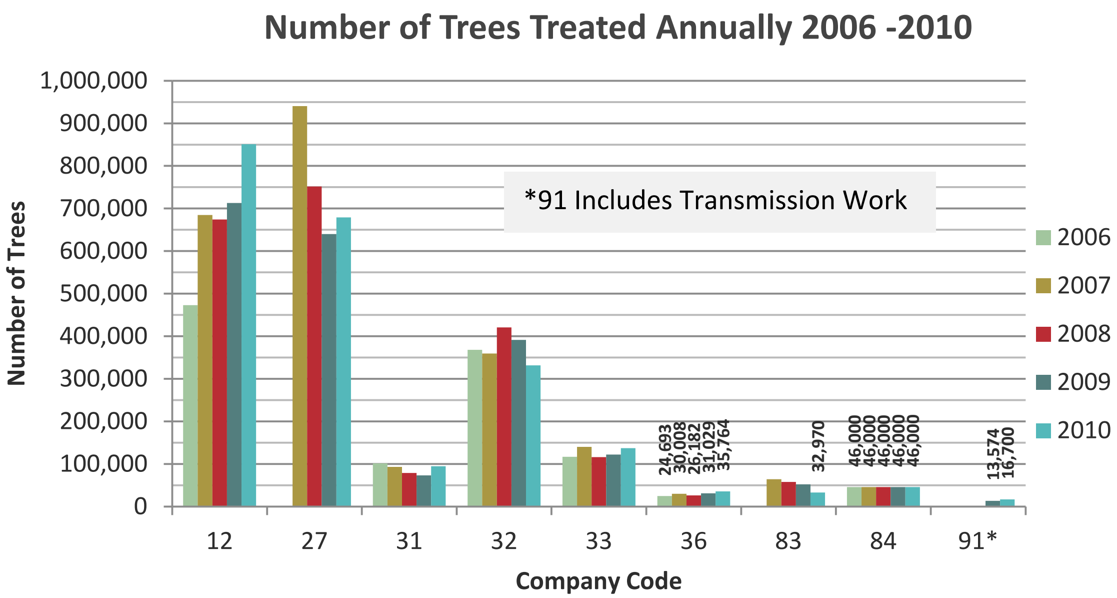

Figure 165: Number of Trees Treated Annually 2006 -2010

COST OF TREES TREATED

Cost of Trees Pruned

Data was collected from **Question #137**

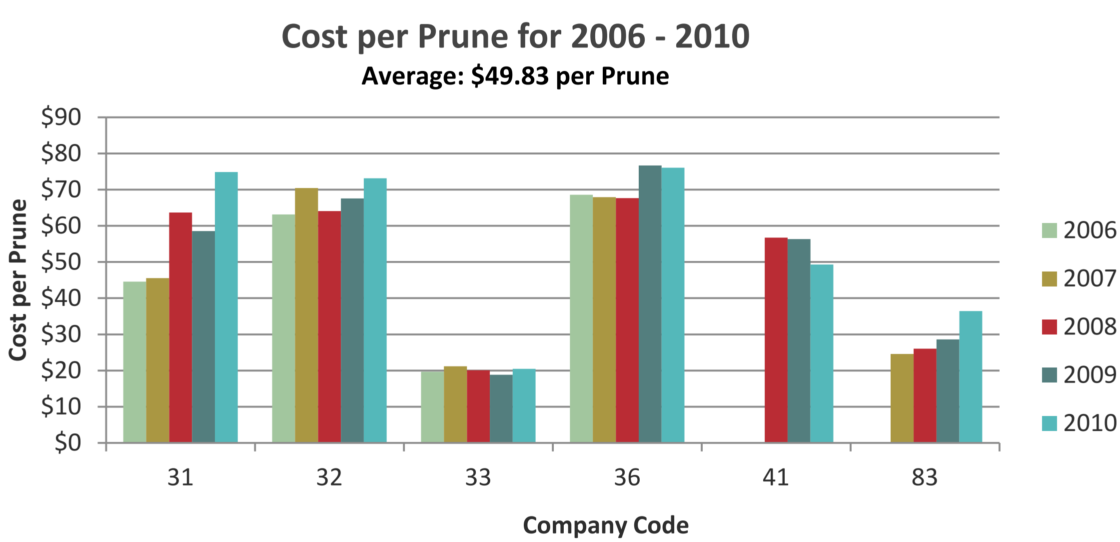

Figure 166: Cost per Tree Pruned for 2006 - 2010

Cost of Trees Removed

Data was collected from **Question #137**

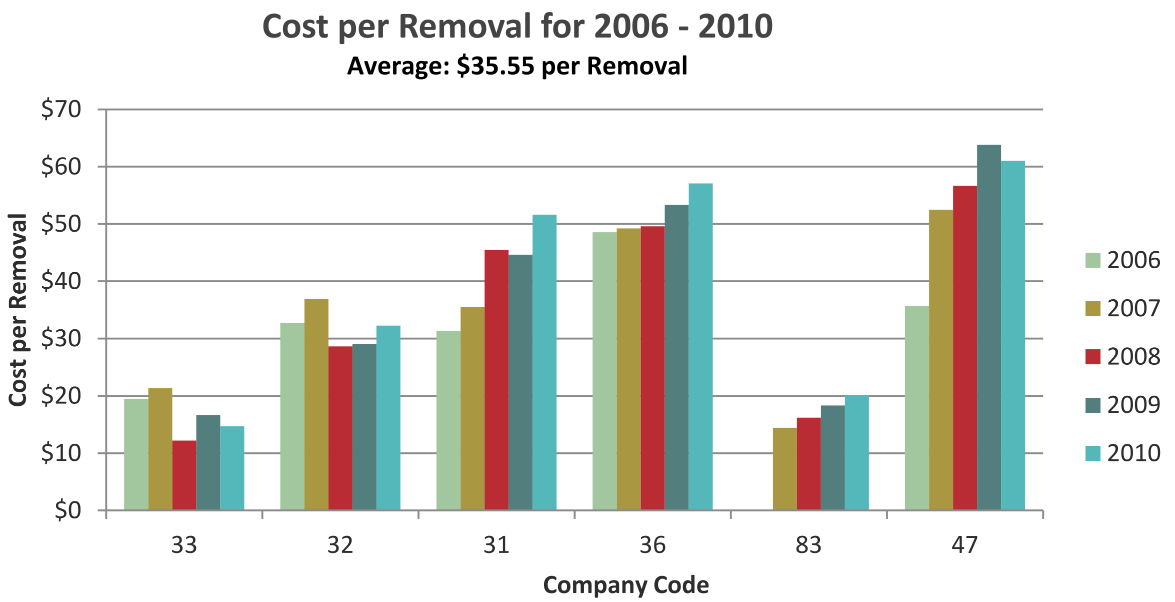

Figure 167: Cost per Tree Removed for 2006 - 2010

Cost of Trees Treated

Data was collected from **Question #137**

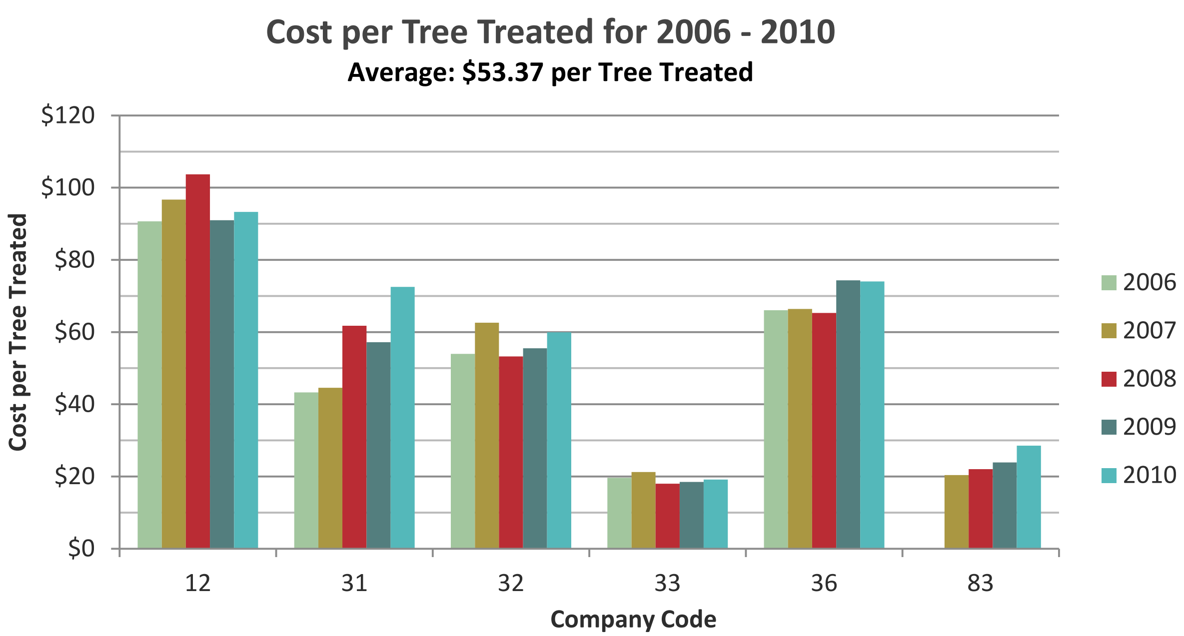

Figure 168: Cost per Tree Treated for 2006 - 2010

LABOR HOURS PER TREE TREATED

Labor Hours per Tree Pruned

Data was collected from **Question #137**

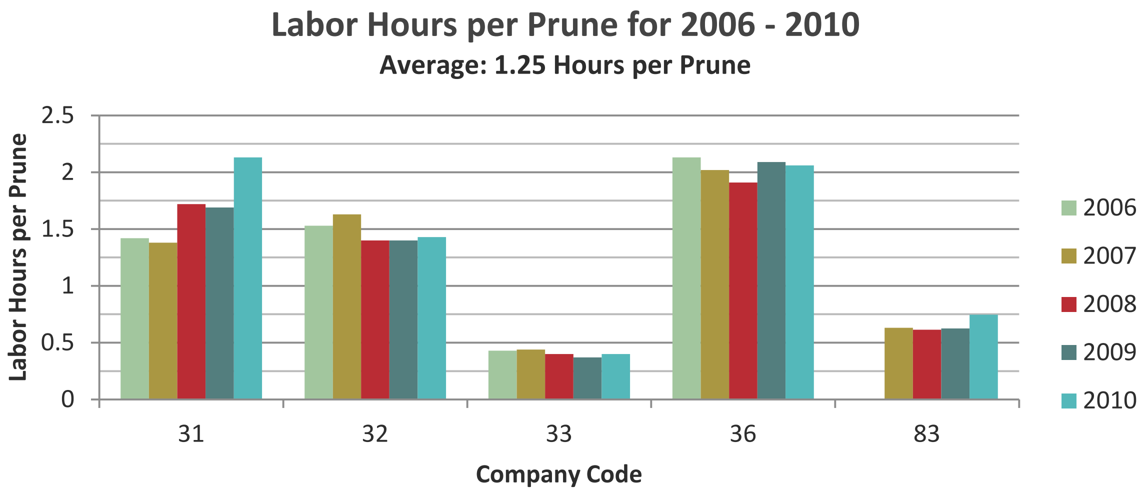

Figure 169: Labor Hours per Tree Pruned for 2006 – 2010

Labor Hours per Tree Removed

Data was collected from **Question #137**

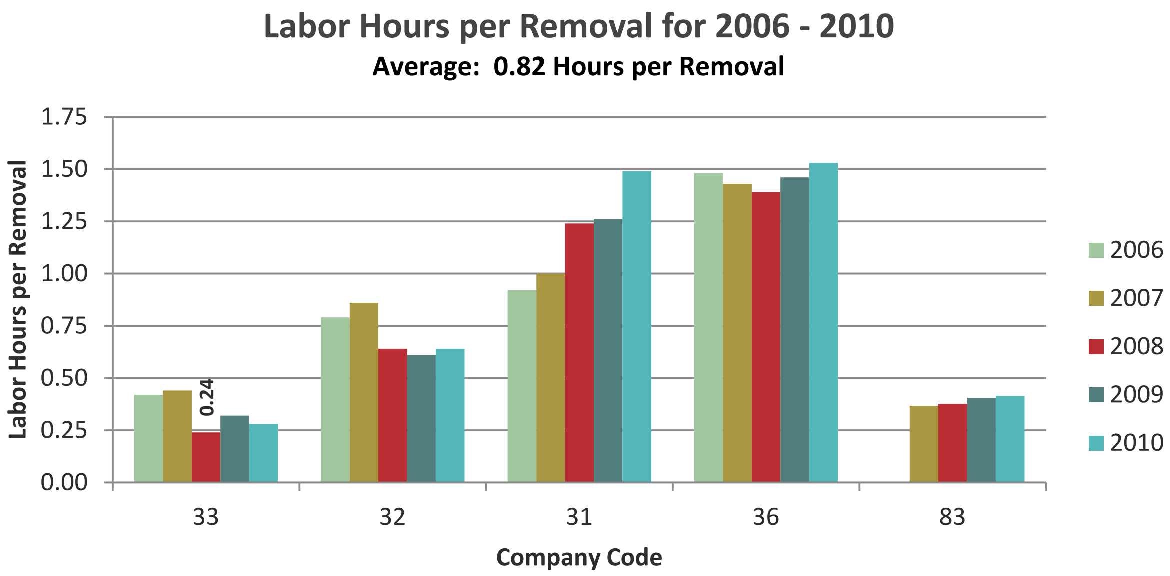

Figure 170: Labor Hours per Tree Removed for 2006 - 2010

Labor Hours per Tree Treated

Data was collected from **Question #137**

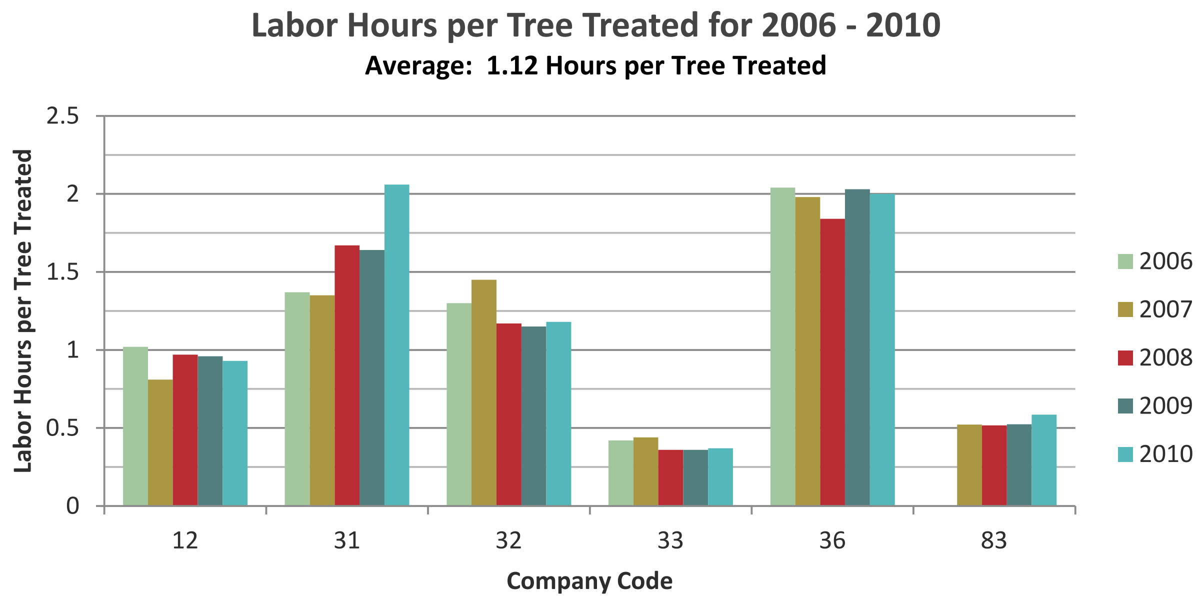

Figure 171: Labor Hours per Tree Treated for 2006 – 2010

PERCENT OF TREES PRUNED VS. REMOVED

Calculated statistic was derived from data collected in **Question #137**

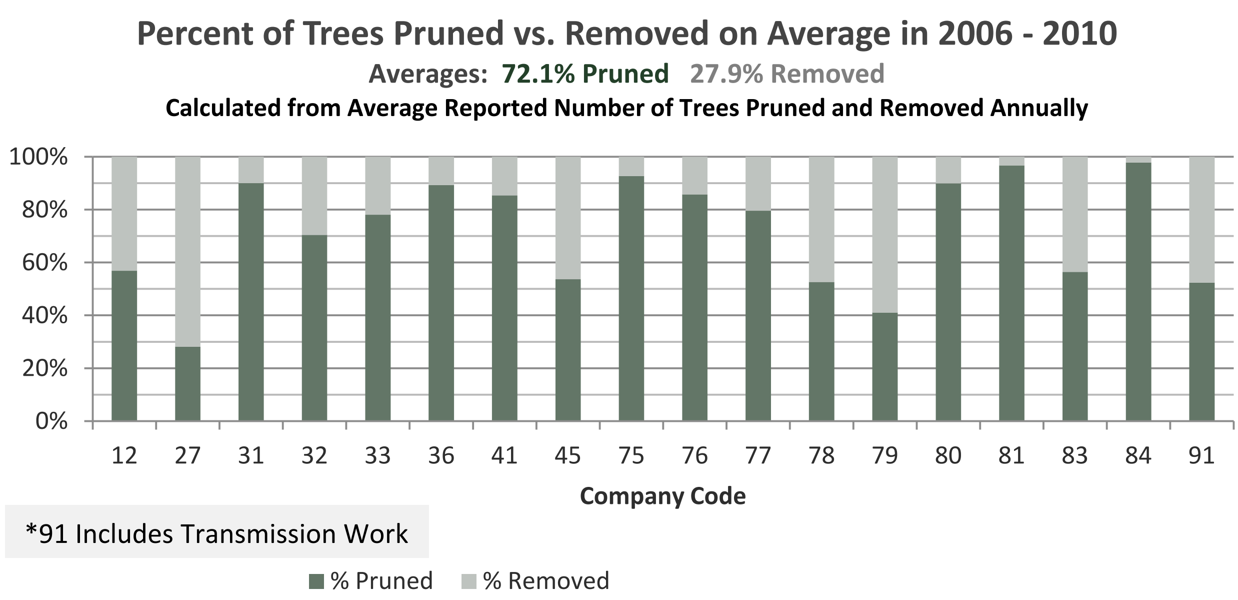

Figure 172: Percent of Trees Pruned vs. Removed on Average in 2006 – 2010

CALCULATION OF PRODUCTION STATISTICS

How Data Is Collected for Production Statistics

Question #138: The answers to the previous question **(#137)** are derived [using one or more of the following categories]: Check all that apply.

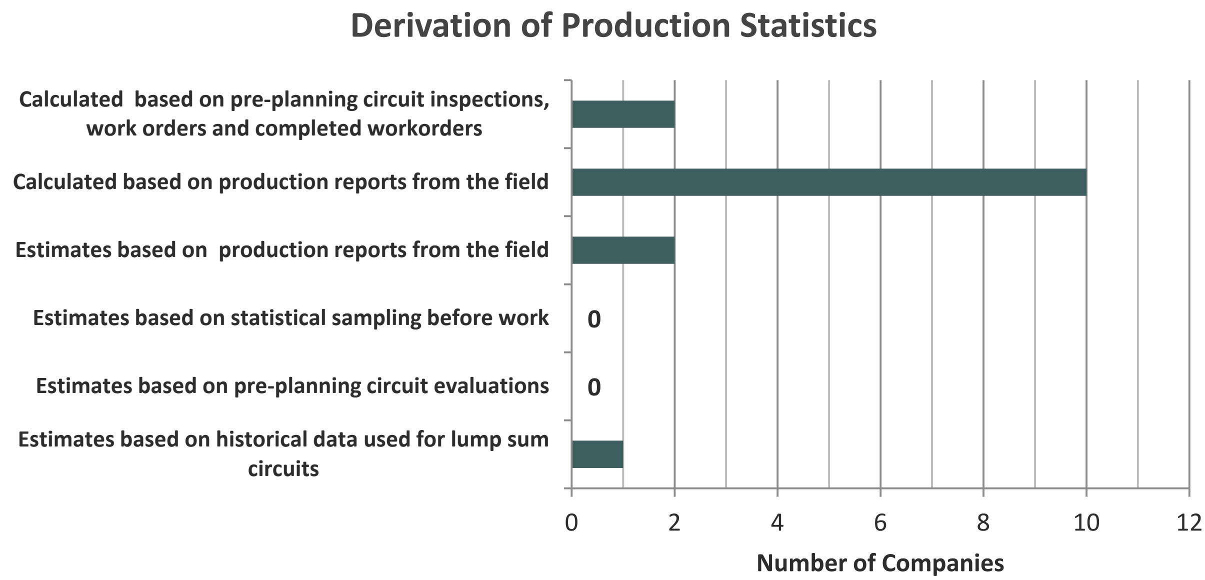

Figure 173: Derivation of Production Statistics

Comments on How Production Statistics Are Collected
About 90% of our treatable tree species that are removed are treated.
These trims and removals include transmission work. We did a great amount of removals in 2009 and 2010 on NERC ROW's. We do not remove a great deal of trees on distribution circuit trimming. We are trying to get the costs of all of the above and will have it by next year's benchmark study.
Not Tracked.
We run the [Contractor Software Name] software, all time and cost is for trimming or removing trees only. Cost do not include any travel time or support.

Figure 174: Comments on How Production Statistics Are Collected

What Activities Are Included in Production Statistics

OBJECTIVE: Between utility companies there are variations in data collection, contract structures and tree crew responsibilities. The objective of this question is to understand how you derive "Cost and labor per prune, removal or treated", since these are NOT standardized.

Question #139: Do your reported calculations "Cost per Tree" and "Labor Hours per Tree" in **Question #137** include the following?

At this point in time, a majority of the companies that supplied production statistics in **Question #137** (Cost per Prune, Cost per Removal, Labor Hours per Prune, etc.) include support activities in their calculations, making the comparisons seen on the graphs generated from this question valid. Of course, these comparisons are not taking into account the economic differences between geographical regions, the kinds of species, and the accessibility to trees, etc. All of these factors would produce differences in cost per unit and labor hours per unit. Also keep in mind that different companies appear on each graph associated with **Question #137** (Figures 162 – 170), so that the comparison of averages would not be valid. The following is a table of comments related to what activities are included in calculations of production statistics.

Comments on and Explanation of 'Other' for What Activities Are Included in Production Statistic Calculations
N/A - all not tracked (3 Companies)
Not tracked this way.
Equipment
Inspecting and laying out work
Next year we will not have any of the subjects costed out, only the total per tree cost.
We run the [Contractor Software Name] software and the activities listed above are all itemized. All activities are added together at the end to determine our cost per line mile.
Unfortunately, our work unit is span, so we cannot answer for pruning data.

Figure 175: Comments on and Explanation of 'Other' for What Activities Are Included in Production Statistic Calculations

PERCENT OF IN-GROWTH OF TOTAL TREES MANAGED

OBJECTIVE: DISCOVER IN-GROWTH PERCENT: In-growth is defined as the number of trees that periodically grow into the smallest inventoried diameter class.

Question #143: Do you know or can you estimate what percent of your tree inventory is in-growth? For the purposes of the benchmark this would be the percent of your total tree inventory, trees that meet your defined minimum DBH, that enter your workload each year.

This question presented a challenge to our benchmark participants. Very few felt confident enough to even attempt a rough estimate. Three companies gave us their best estimates, but none of them had made any measurements to determine this percentage. The three estimates were **two at 10% and one at 5%**.

The company that estimated 5% in-growth made the following comment: "Our brush control program removes ROW floor to the ground. Estimated in-growth is an estimate of the % of trees on the ROW floor that grow to 4+in DBH." This particular company has based their estimate on some empirical evidence.

UNIT PRICING

Use of Unit Prices in Contract Structures

Question #144: Instead of paying for UVM services by time units, do you pay for some or all UVM services by physical units, such as trees pruned, trees removed, spans mowed, miles treated, brush units cut, etc?

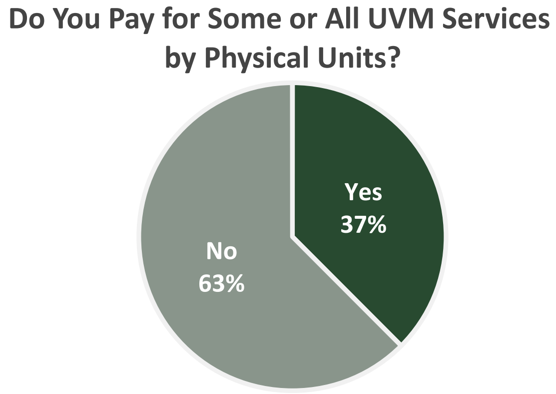

Figure 176: Do You Pay for Some or All UVM Services by Physical Units?

In 2002 and 2006 participants were asked “How are your tree pruning and removal contracts structured?”

In **2002,** only **14%** responded *Unit Price*. In **2006 22%** responded *Unit Price*.

Although the question asked in 2002 and 2006 was slightly different, it is possible to say that the percent of companies using unit prices as a component of their contract bidding structure is increasing.

Definitions of Units Used for Pricing

Pruning Units ("Tree Unit Type")

Question #145: If the cost of your program or parts of your program is measured and paid for according to specific tree units, please list the units you use to quantify trees prunes, such as top prune, side prune, v-prune and overhang prunes. Please provide the name of the unit and a brief explanation or definition.

Pruning Unit Types
Tree Trimmed: For tree trimming purposes, a tree qualifying for "tree trimmed" status shall be defined as being a plant with a central trunk that is four (4) inches or larger DBH and where final are cuts are made above four and one-half feet (4.5) from the ground. Any plant less than four (4) inches DBH shall be reported as brush. TT [Tree trimming] work where final cuts are made at or below four and one-half feet (4.5) from the ground is considered a removal. Multiple stems originating from the same common root crown shall be considered as one (1) tree.
8-11.9in, 12-15.9in, 16-19.9in, 20-23.9in, 24-28in, and >28in DBH additional overhang (5 types)
Cost per tree trimmed based on DBH size class

Figure 177: Pruning Unit Types

Brush Units ("Tree Unit Type")

Question #149: If the cost of your program or parts of your program is measured and paid for according to specific "tree" units, please list the units you use to quantify brush units, such as square feet/meters, acres/hectares, etc. Please provide the name of the unit and a brief explanation or definition.

Brush Unit Types
Brush Cut/Trim: Any plant or group of plants that do not qualify as a tree trimmed or removed as defined above, shall be reported as units of brush. The portion of plant material to be removed shall qualify as contributing to a unit. One (1) unit of brush shall be defined as ten (10) cubic yards (270 cubic feet, i.e., a space represented by a cube which is 6.5 feet in all dimensions) of standing plant material. For reporting purposes, units shall be identified in increments of 1/10th.
Kms of brush completed (1 km is roughly 1 ha)
BRUSH REMOVAL (PER LINEAR FT, Hand-cutting)
Single-phase half-span, single phase span, triple-phase half-span, and triple-phase span (4 types)
High - >30 stems per span; Medium - 15 - 30 stems per span; Low <15 stems per span.

Figure 178: Brush Unit Types

Removal Units ("Tree Unit Type")

Question #147: If the cost of your program or parts of your program is measured and paid for according to specific tree units, please list the units you use to quantify trees removals, such as 4-12" DBH, 12-24" DBH, etc. Please provide the name of the unit and a brief explanation or definition.

Removal Unit Types
Tree Removed - Category 1: For tree removal purposes, a tree qualifying for "tree removed-Category 1" status shall be defined as being a plant with a central trunk that is at least four (4) inches in diameter and less than twelve (12) inches DBH and where final are cuts are made at or below four and one-half feet (4.5) from the ground. Any plant less than four (4) inches DBH shall be reported as brush. Multiple stems at least four (4) inches DBH originating from the same common root crown shall each be considered as one (1) tree. Multiple stems less than four (4) inches DBH shall be considered brush.
Tree Removed - Category 2: For tree removal purposes, a tree qualifying for "tree removed-Category 2" status shall be defined as being a plant with a central trunk that is at least twelve (12) inches and less than twenty-four (24) inches DBH and where final are cuts are made at or below four and one-half feet (4.5) from the ground. Multiple stems at least twelve (12) inches DBH originating from the same common root crown shall each be considered as one (1) tree.
Tree Removed - Category 3: For tree removal purposes, a tree qualifying for "tree removed-Category 3" status shall be defined as being a plant with a central trunk that is at least twenty-four (24) inches and less than thirty-six (36) inches DBH and where final are cuts are made at or below four and one-half feet (4.5) from the ground. Multiple stems at least twenty-four (24) inches DBH originating from the same common root crown shall each be considered as one (1) tree.
Tree Removed - Category 4: Trees thirty-six (36) inches or larger DBH where final are cuts are made at or below four and one-half feet (4.5) from the ground.
1-4 in, 4.1 – 12 in, 12.1 – 24 in, 24.1 – 36 in, >36 in DBH (5 types)
8 – 11.9 in, 12 – 15.9 in, 16 – 19.9 in, 20 -23.9 in, 24 – 27.9 in, 28 – 31.9 in, 32 – 35.9 in, 36 – 40 in DBH, CUT AND LEAVE, >40" DBH CUT AND LEAVE (NEGOTIABLE) (9 types) Within these DBH size classes we have (3) different costs associated with them based on what is specified by the forester. These (3) are classified as: Cut-n-Leave, Cut-n-Chip, & Cut-n-Haul. Each has a different cost associated with them.
Vine Removal Unit, 0-12" DBH, 12-20" DBH, 20-28" DBH, 28-36" DBH, > 36" DBH. Each can be broken into A, B, or C category. C = All debris stays – Make safe; B = Remove to ground and remove all debris, brush, and wood; A = Remove to ground - chip brush - wood stays.

Figure 179: Removal Unit Types

Span or Mile/Kilometre Units ("Aggregate Unit Types")

Questions #152 and #154: If the cost of your program or parts of your program is measured and paid for according to larger aggregate units such as span or miles/kms, please list the units you use to quantify your work, such as 1/4 spans, 1/2 spans, 3/4 spans, whole spans, manual spans, mechanical spans, herbicide spans, mowing spans, etc., or mile/km of mechanical, mile/km of manual crew, mile/km of herbicide, mile/km of mowing, etc. Please provide the name of the unit and a brief explanation or definition.

Aggregate Unit Definitions
All cycle maintenance priced and paid by mile. Mile of overhead conductor (open wire). Mile of overhead conductor ONLY.
[Units based on] Km completed. [Unit Types:] $/Km Line Clearing; $/Km Brush Control; $/Km Customer Notification
[Unit Types:] 1) Single phase half span cleared (brush) off road and on-road; 2) Single phase span cleared (brush) off road and on-road; 3) Triple phase half span cleared (brush) off road and on-road; 4) Triple phase span cleared (brush) off road and on-road; 5) Half span pruned on-road; 6) Half span pruned off-road; 6) Span pruned on-road; 7) Span pruned off-road
[Unit Types Measured in] Miles/Acres. Trimming is based more on Line Miles where as individual tree removals have an agreed upon cost associated based on contract agreement. Herbicide measurement is based on acres and in some cases spans or line miles.
[Unit Types:] 1) Rate per feeder mile - cost to clear one mile to specs per area; 2) Rate per lateral mile - cost to clear one mile to specs per area. Distribution territory divided into 16 areas - each with a feeder and lateral cost per mile

Figure 180: Aggregate Unit Definitions

Unit Prices per Unit

Reported *Unit Prices* are displayed on the next three tables. To maintain confidentiality, companies are not identified by company code, but rather by region of the continent that they are located in. *Unit Prices* are the average of all their units (described in the above tables of definitions).

Benchmark participants are from Canada and the US. The location of the company is shown on the left. Canadian companies all would have "North" or "Northern" in their location and the northern states in the US would also have "North" or "Northern" in their location titles. To further maintain confidentiality, a company will not be identified as to their national affiliation. All costs have been converted to US dollars.

Average Unit Prices and Labor Hours for "Tree" Unit Types

OBJECTIVE: To compare the resources used to perform units under a unit price program to the same units of work under an in-house, time and material, and lump sum programs.

Question #151: Based on the on the various individual pruning, removal and brush units you have used over the past three years (2008-2010), please enter the AVERAGE amount of labor hours and/or cost for each of the following basic units you measure under a unit priced program.

AVERAGE COSTS AND LABOR HOURS PER UNIT TYPE

Company Location	Average Labor Hours per Prune	Average Cost per Prune	Average Labor hours per Removal	Average Cost per Removal	Average Labor Hours per Brush Unit	Average Cost per Brush Unit	Average Labor Hours per Herbicide Unit	Average Cost per Herbicide Unit
North Central					33.61	$2,718.38 Per 2.5 acres		
South East				$250.00		4 (Per Linear FT, Hand-cutting)		
Western	1.87	$66.43	1.34	$47.59	0.0258	$0.96	0.0260	$2.73
North Central	1.41	$67.87	0.63	$29.87	0.0186	$0.90	0.0028	$0.15
North Central	0.39	$19.79	0.28	$14.26	0.0046	$0.26	0.0018	$0.09
South and South Western	2.03	$73.95	1.46	$53.47	0.0180	$0.67	0.0114	$344.00
North Eastern		$246.98 per span*		$59.80		$273.67 per span	No Herbicides	
North Central	0.8	$35.94	0.45	$26.91				
Averages	**1.3**	**$52.80**	**0.832**	**$68.84**				
Range Maximum	**2.03**	**$73.95**	**1.46**	**$250.00**				
Range Minimum	**0.39**	**$19.79**	**0.28**	**$14.26**				

Figure 181: Average Costs and Labor Hours per Unit Type by Region and Company

* This value was excluded from the average for prunes, since unit was defined as a span for this company.

Averages and ranges are included for the *Prune Units* and *Removal Units* in the last three rows of the chart. Brush and Herbicide Unit averages are not included, because the definition of unit for these activities varied greatly. The definition for a tree, the unit used for prunes and removals, also varies between companies, but not to as great of an extent. Some of the companies on this chart did not define their brush unit. All costs have been converted to US dollars.

Unit Pricing vs. Other Contract Structure Costs for "Tree" Unit Types

A comparison can be drawn between unit pricing and other contract structures. The averages from **Question #151** (above table) and **Question #137** are compared on the following graph.

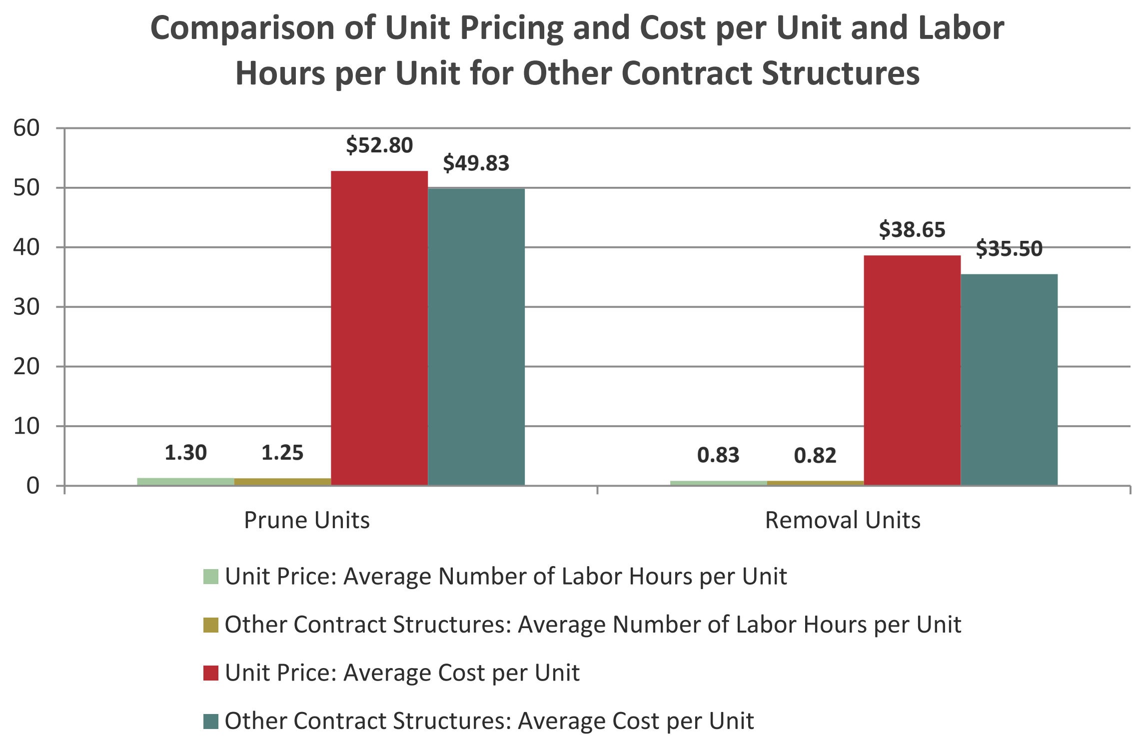

Figure 182: Comparison of Unit Pricing and Cost per Unit and Labor Hours per Unit for Other Contract Structures

It should be noted that *Unit Prices* include all costs (supervision, overheads, clean-up, etc.), while cost per prune and cost per removal (question #137) may not include all costs associated with the work. Activities included in reported calculations of cost per prune or removal are referred to in table for question #139.

Average Prices and Labor Hours for "Span" Unit Types ("Aggregate Units")

AVERAGE UNIT PRICES FOR SPANS AS UNIT TYPE

Company Location	Average Labor Hours per Span	Average Cost per Span	Average Cost per Span Manually Cleared	Average Cost per Span Mechanically Pruned	Average Cost per Span Mowed	Average Cost per Span Herbicide Treated	Comments
North Central	15.78	$792	$359	$441	$72.19	$6.24	The average cost to trim or manually clear does not include management or support cost.
North Eastern		$250.57	$273.66 (manual, mechanical or mow, no distinction)	$246.98			These numbers are balanced averages based on more than half a million spans pruned or cleared in the 3 last years.

Figure 183: Average Unit Prices for Spans as Unit Type

The table above and the one on the next page represent costs associated with units defined as spans or partial span lengths and for units defined as miles for 2011. Some of the participants that answered these questions used the information gleaned from T & M operations. Once again, these companies are from Canada and the US. The location of the company is shown on the left. Canadian companies all would have "North" or "Northern" in their location and the northern states in the US would also have "North" or "Northern" in their titles. To maintain confidentiality, a company will not be identified as to their national affiliation. Costs and metric measurements have been converted to US dollars and miles.

Average Prices and Labor Hours for “Mile” Unit Types (“Aggregate Units”)

AVERAGE UNIT PRICES FOR MILES AS UNIT TYPE

Company Location	Average Labor hours per Mile	Average Cost per Mile	Average Cost per Mile Manually Cleared	Average Cost per Mile Mowed	Average Cost per Mile Herbicide Treated	Comments and Clarification
Southeast	150.65	$5,101.38				Distribution territory divided into 16 areas - each with a feeder and lateral cost per mile. Rate per feeder mile or per lateral mile - cost to clear one mile to specs per area.
North Central	164.22	$17,386.99				$/Mile Line Clearing, Brush Control and Customer Notification
North Central		$7,453.00		$1,340.00	$109.00	All work is done on a TM basis
North Central		$3,968.00	$11,159.00	$0.00	$263.00	Miles as shown on the feeder map
Northeast		$4,016.23 for every mile affected by vegetation			No Herbicide	We prune a lot more than we clear. We clear span where we can (we clear a span only if it eliminates pruning the year after), in the same mile we prune the year after.
Southeast		$2,660.00				Mile for Mechanical Trimmers. Cost per mile for Pro-active Maintenance trimming

Figure 184: Average Unit Prices for Miles as Unit Type

PROGRAM DRIVERS, LAWS, REGULATORY INFORMATION AND UTILITY GOVERNING BODIES

UVM PROGRAM OBJECTIVES

Question #156: Please rank the following in order of importance regarding your utility vegetation management program: NOTE: Use each rating category only once. In other words, only one objective can be ranked most important and only one objective can be ranked 2nd, etc.

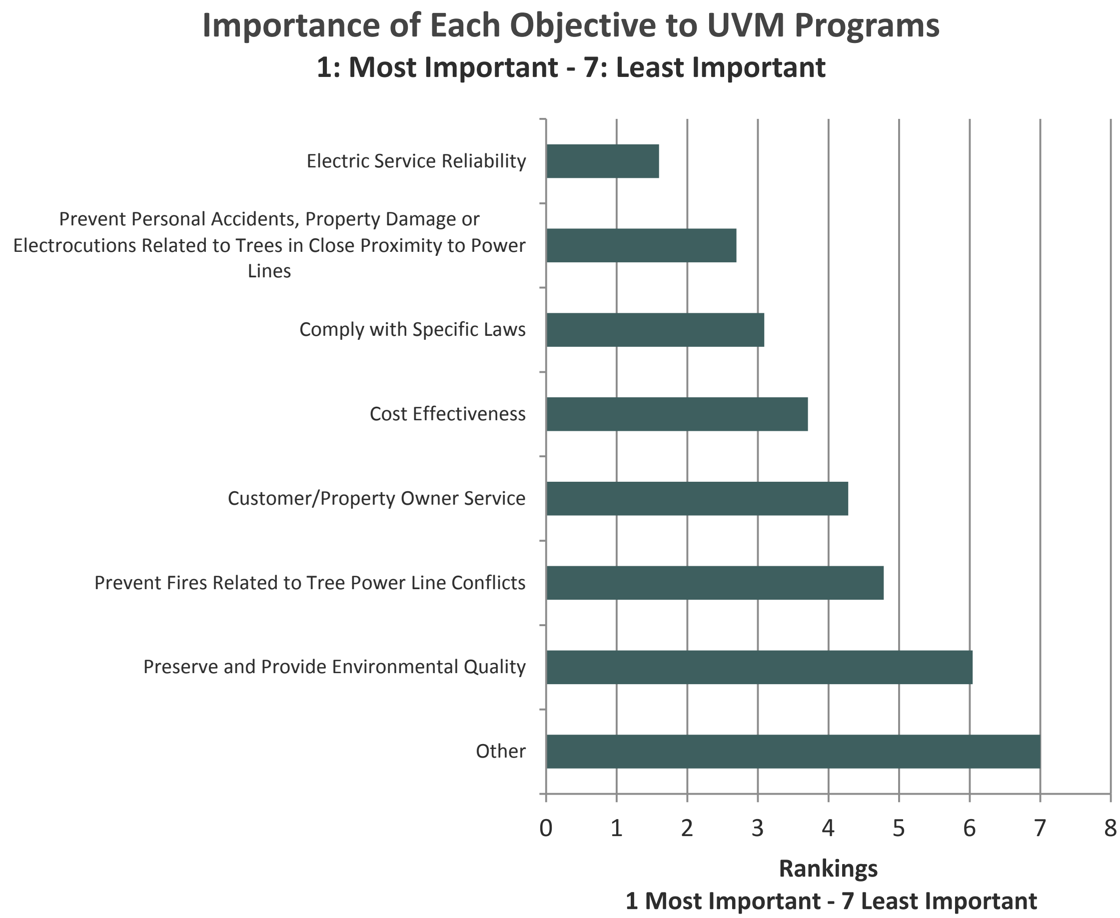

Figure 185: Importance of Each Objective to UVM Programs

Electric Service Reliability has the smallest weighted ranking (Most Important) followed closely by *Prevent Personal Accidents, Property Damage or Electrocutions Related to Trees in Close Proximity to Power Lines*. The most important driver is at the top of the graph and they decrease in importance as you move down.

A second graph (below) using the same data gives a more detailed understanding of the importance of each program driver to benchmark participants.

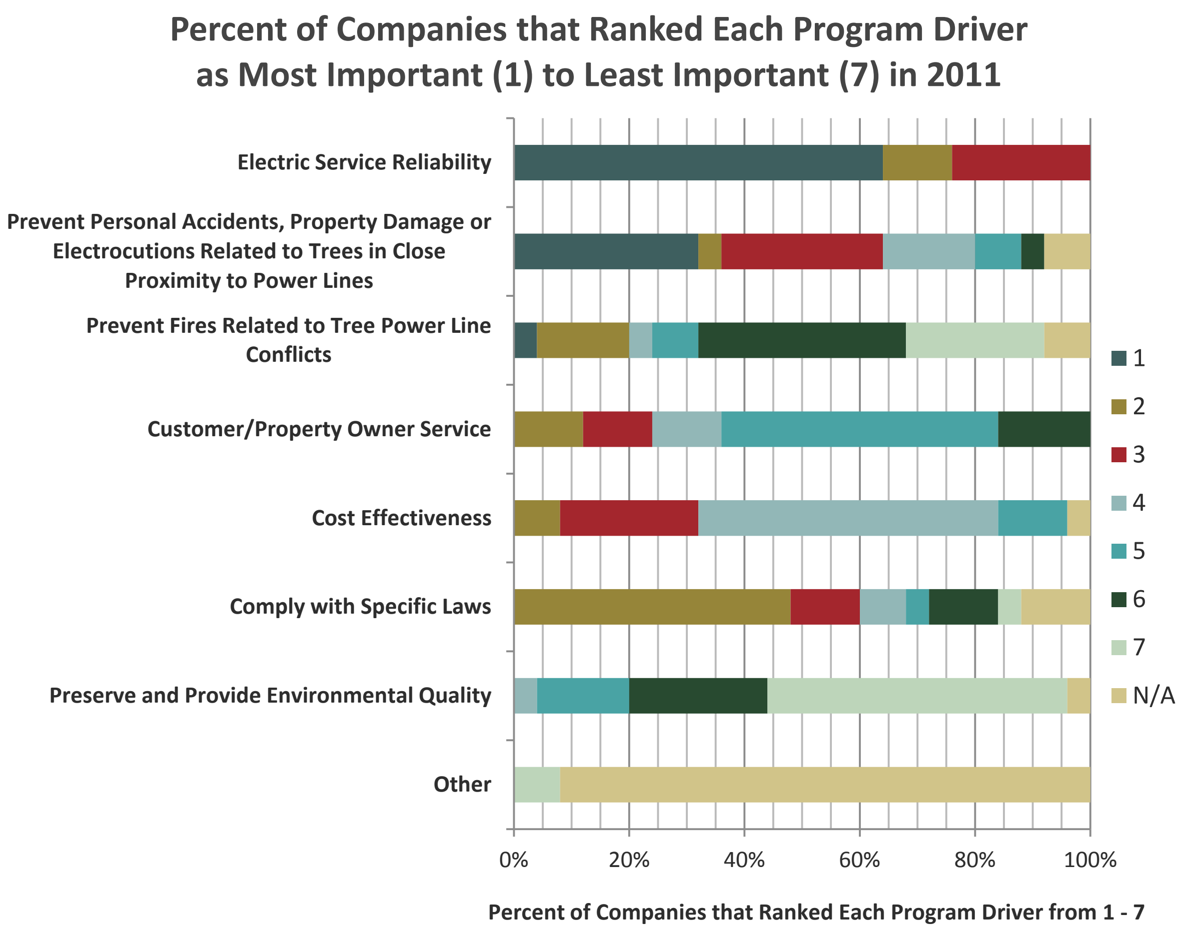

Figure 186: Percent of Companies that Ranked Each Program Driver as Most Important to Least Important in 2011

Comments on the Ranking of the Importance of Program Drivers
All of the 7 items you have listed above are very important to our company. At a given site, the ranking could easily change but overall I would rank them as shown above.

Figure 187: Comments on the Ranking of the Importance of Program Drivers

Data Discussion about UVM Program Drivers

The most important program driver is on the top of the charts (Figures 184 & 185). It should be noted that in the overall rankings *Prevent Fires Related to Tree Power Line Conflicts* placed 6th in the weighted rankings (*Importance of Each Objective to UVM Programs*, above), which means that it was a low priority for most utilities. Yet, the graph (Figure 185) above shows that almost 30% of the respondents ranked it as the most or the second most important objective. It is obvious that this objective is a regional one and over 10% of companies do not even rank it as an objective (N/A). Other areas of note is the ranking of *Electric Service Reliability* and *Prevent Personal Accidents, Property Damage or Electrocutions Related to Trees in Close Proximity to Power Lines,* which were both ranked 1st by 47% of the companies that responded. It was in the number of companies that ranked "Safety" 2nd that placed *Electric Reliability* as the number one driver in the previous graph (*Importance of Each Objective to UVM Programs*, above). In the **2006** Benchmark Survey, *Prevent Personal Accidents, Property Damage or Electrocutions Related to Trees in Close Proximity to Power Lines* was the number one program driver. In 2006, almost **70%** of companies ranked this driver as most important. We are definitely seeing a trend toward electric reliability being more important than in the past. In all likelihood this is driven from outside the UVM department.

LAWS AND REGULATIONS

Utilities Subject to Regulations by State and/or Public Utility Commission

Question #157:

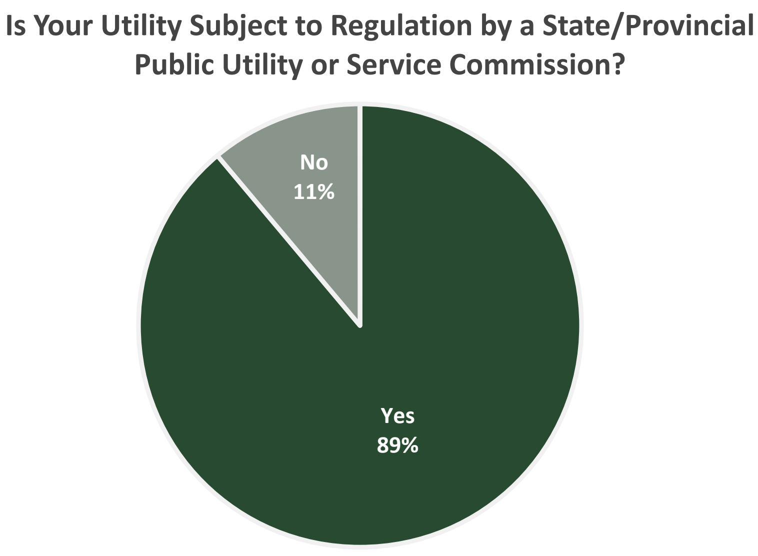

Figure 188: Percent of Utilities Subject to Regulations by State and/or Public Utility Commission

Percent of Companies to Which Specific Laws and Regulations Apply

Question #158: Which of the Following Laws or Regulations Apply to Your Operations?

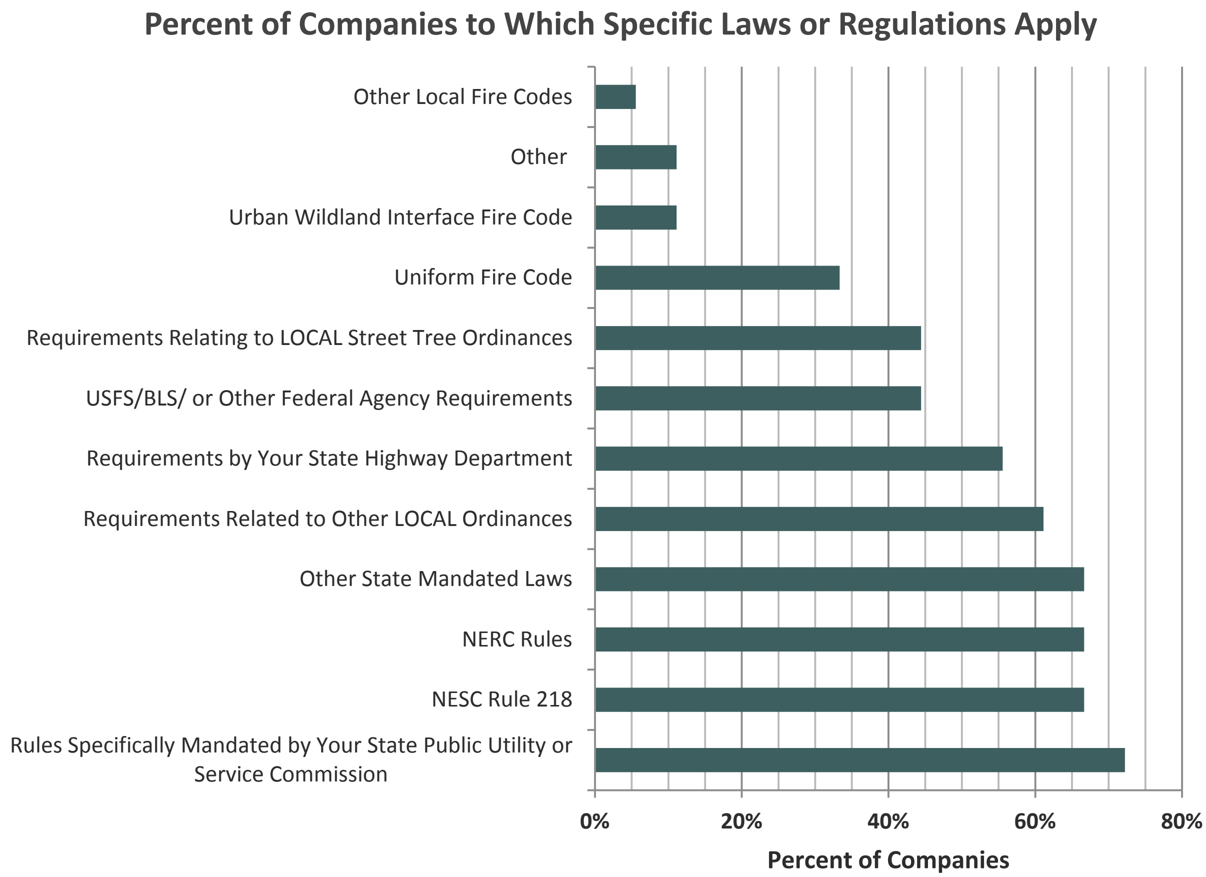

Figure 189: Percent of Companies to Which Specific Laws or Regulations Apply

Activities Regulated by Public Utility Commission Rules or State Laws

Question #159: Which of the following UVM activities are subject to Public Utility Commission (PUC) rules or state laws? Check all that apply.

Benchmark Participants were able to indicate all activities that applied to their UVM program. The activities that had the most percent of companies subject to regulation by PUC or state regulations appear at the bottom of the graph, decreasing as you read up.

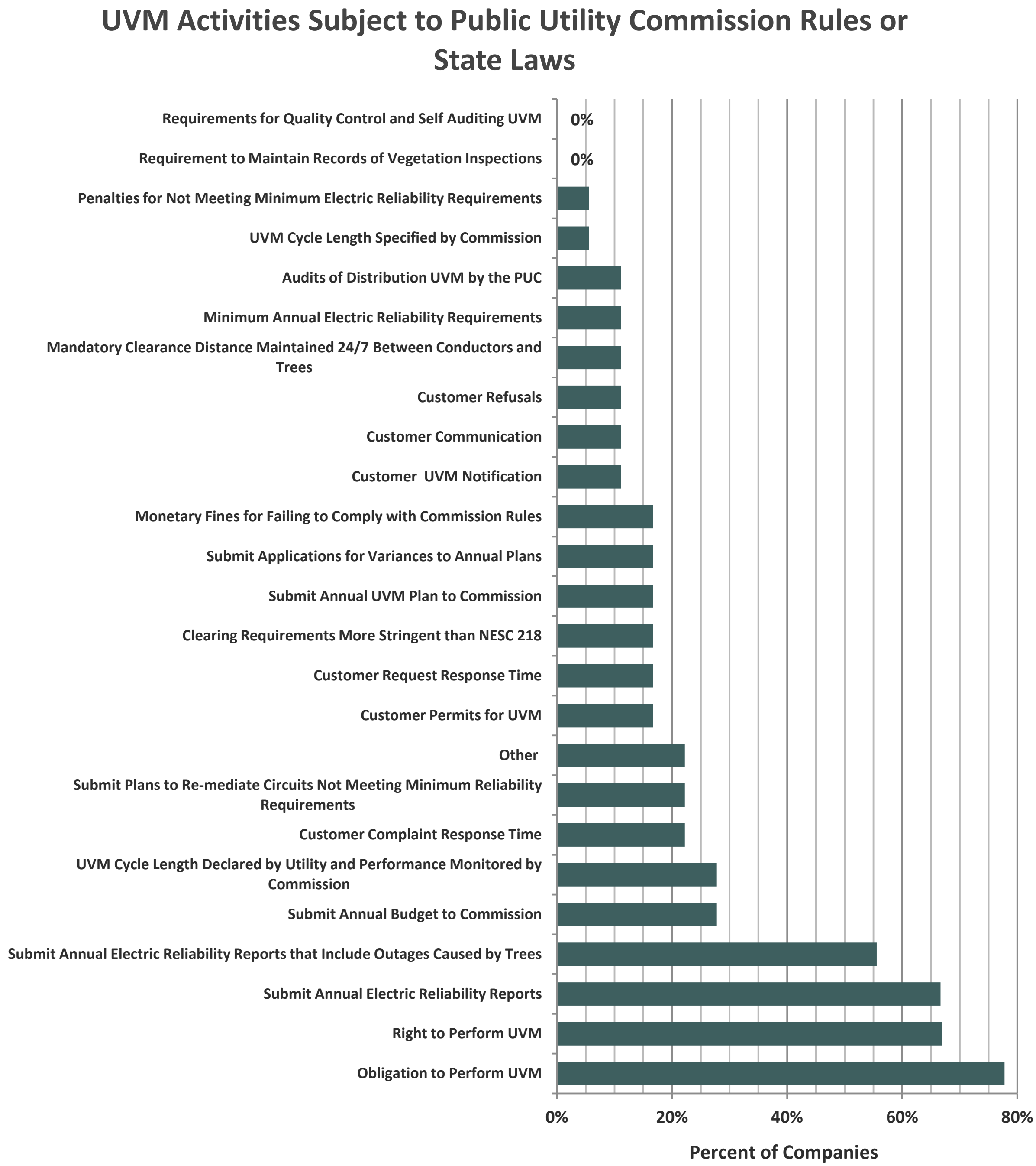

Figure 190: Activities Subject to Public Utility Commission Rules or State Laws

Other Activities Subject to PUC Rules and State Laws
Required to report major incidents.
The more stringent requirements come from Oregon and California only.
None of the above.
We are a Co-op and are regulated by the Board of Directors which help create and approve of our bylaws.

Figure 191: Comments and Other Activities Subject to PUC Rules and State Laws

Mandatory Clearance Requirement Laws and Regulations

Question #160: If you answered that you do have mandatory clearance requirements, please describe the requirement here and include the name/number of the rule(s), standard(s) or law(s).

Description of Mandatory Clearance Requirements
California Public Utilities Commission General Order 95, Rules 35 & 37 California Public Resources Code 4293
OR Administration Rule 860-024-[00]16; Cal Resource Code 4292, 4293; Cal Public Utility Co General Order 95, Rule 35

Figure 192: Description of Mandatory Clearance Requirements

Specific Cycle Length Requirement Laws and Regulations

Question #161: If you answered that you have a rule requiring a specific cycle length or another aspect of cycle management, please describe the rule(s) here, including the name/number of the rule(s).

No Comments Yet

Minimum Reliability Requirement Laws and Regulations

Question #162: If you answered that you have minimum reliability requirements, please describe the requirements and how the measurements are made.

Description of Minimum Reliability Requirement
[State] PUC Substantive Rule 25.52: SAIDI less than or equal to 101.55. No specific penalty in rule.

Figure 193: Description o f Minimum Reliability Requirements

Mandatory Clearance Requirements

The following questions involved attitudes and expense associated with mandatory clearance requirements.

Attitudes towards Mandatory Clearance Requirements

Question #163: Do you think mandatory clearance requirements are __________?

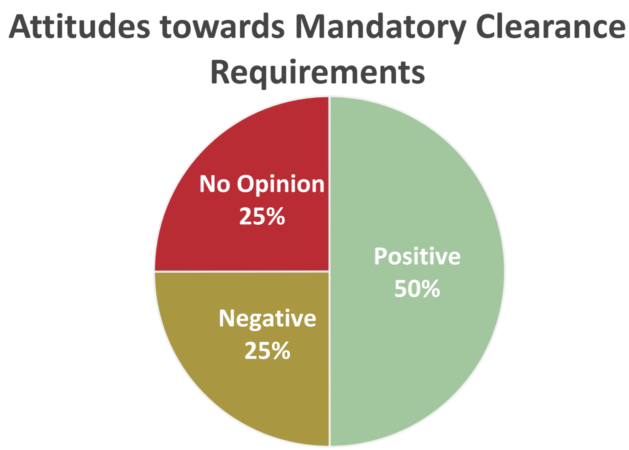

Figure 194: Attitudes towards Mandatory Clearance Requirements

The next graph shows the changes in attitudes towards mandatory clearance requirements over time. The data indicates a marked increase in positive attitudes towards these requirements. The positive attitude was a **34% increase** with an equal decrease in negative attitudes. Companies with no opinion remained relatively static.

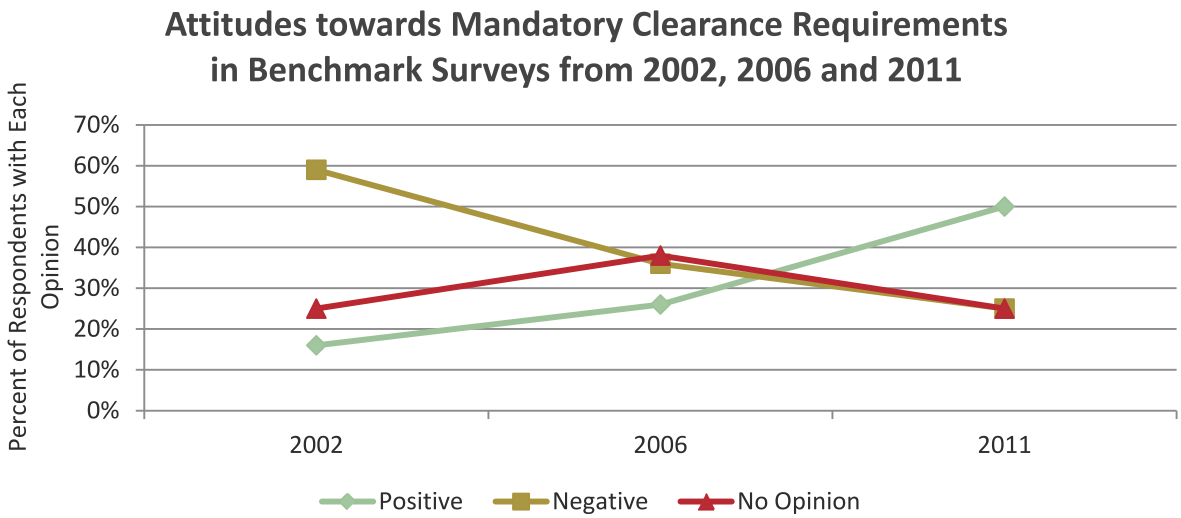

Figure 195: Attitudes towards Mandatory Clearance Requirements in 2002, 2006 and 2011

Comments collected from **Question #163**

Explanations of Attitudes Towards Mandatory Clearance Requirements
Positive: Outside agency would be dictating what needed to be done and that would help with customer agreements. (3 companies responded this way) [Responded with **Positive** Feelings]
Costs. We would like mandatory clearance at time of pruning for more strength. Will not work for all species of tree. [Responded with **Negative** Feelings]
Helps to prevent fires and outages. [Responded with **Positive** Feelings]
Helps to defend budgets and justify spending. [Responded with **Positive** Feelings]
Our required clearances are defined by cycle length. Clearances can vary from species to species depending on the length of the cycle. [Responded with **Negative** Feelings]
Mandatory 24/7 clearance requirements would provide clear expectations and provide tangible action thresholds to use in an integrated management approach. That being said, a mandatory clearance requirement at time of trimming would be a negative requirement as it will likely impose unreasonable expectations in some situations. Although in theory mandatory clearance requirements would be positive, operationally they would be very difficult to meet and depending on penalties may do more harm than good. [Responded with **Positive** Feelings]
We might be able to get on a cycle if it was mandated and better serve the customers through reliability. [Responded with **Positive** Feelings]
Both positive and negative. Positive for UVM programs looking for consistent levels of funding. Negative to Utilities because there is a loss of flexibility on how to expend their resources. Negative to Utilities when penalties are attached to these requirements. [Responded with **No Opinion**]
A mandate has ability to have a negative impact to your business and your customers. [Responded with **No Opinion**]
It belongs to us to define the best strategy to maintain a security clearance for a reasonable cost. [Responded with **Negative** Feelings]

Figure 196: Explanations of Attitudes towards Mandatory Clearance Requirements

Compliance Capabilities to Meet Mandatory Clearance Requirements

Question #164:

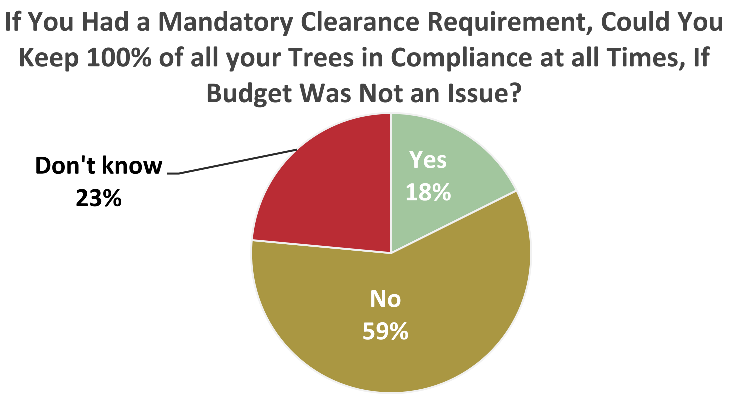

Figure 197: Compliance Capabilities to Meet Mandatory Clearance Requirements

Compliance Capabilities to Meet Mandatory Clearance Requirements
There is no guarantee that [the budget] would be adequate. (4 Companies) [Answered: No]
It would take more crews/contractors than are available. Competition for available resources (between utilities) would drive costs up. [Answered: No]
We do have mandatory clearance requirements and our non-contact compliance is 99.76% (182 non-compliant [trees]/76,151 of trees statistically sampled) but that is not 100%. To eliminate that last increment would be astronomically costly. [Answered: No]
Preposterous question - if we could hire one person per tree we could meet this requirement. [Answered: Yes]
Palm trees cannot be properly maintained and require customer permission to remove. [Answered: No]
Using a planned cyclical maintenance program on a short cycle in combination with frequent inspections and corrective action programs, maintaining clearances should be achievable. [Answered: Yes]
Budget will always be an issue. It may require coming back every year rather than letting it go until we get back on the circuit for a cycle trim. [Answered: Don't Know]
Not possible to know what every tree on your system is doing at any point in time. [Answered: No]
Storms, natural causes [would make compliance with mandatory clearances unattainable]. Also distribution lines have very weak easement rights; they would need to be strengthened in order to be in compliance. [Answered: No]
You will always have some individual [trees] nearby the wires. Growing rates are too variable, even for the same species. [Answered: No]
With all the different timber types and terrain changes within our service territory, we do not believe that we could keep 100% compliance, regardless if budget was not an issue. With over 90,000 overhead line miles to manage, the costs associated with 100% compliance at all times would not be feasible. [Answered: Don't Know]
Budgets are always an issue. [Answered: Yes]

Figure 198: Compliance Capabilities to Meet Mandatory Clearance Requirements

Data Discussion of Mandatory Clearance Compliance Capabilities

Even the company that has requirements and tracks their compliance by statistical surveys believed 100% compliance was not economically possible. As one participant comments, "… if we could hire one person per tree we could meet this requirement." Perhaps the question here is ***not*** whether 100% compliance is possible, but whether greater than 99% compliance can be achieved (as seen in the comment, "…compliance is 99.76%.").

Mandatory Clearance Requirements Projected Impact on UVM Budgets

Question #165: How much would you have to increase your budget in order to comply with a 100% Mandatory Clearance Law?

Mandatory Clearance Requirements Projected Impact on UVM Budgets
Unknown (3 companies)
Triple (depending on clearance)
Unknown - I estimate as least double.
Another ridiculous question - see above - millions
Almost double
Triple (2 Companies)
At least triple, probably more.
6x
Nearby double
100% mandatory clearance would cause a substantial increase to our budget.

Figure 199: Mandatory Clearance Requirements Projected Impact on UVM Budgets

GOVERNMENT AGENCY COMPLAINTS

Tracking Government Agency Complaints

Question #166:

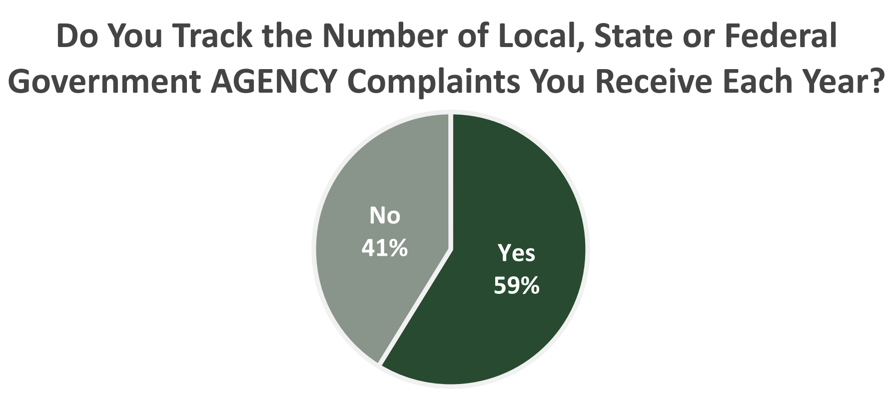

Figure 200: Percent of Companies that Track Number of Agency Complaints Received Annually

Number of Annual Government Agency Complaints

Question #167: If yes [to question #166], how many AGENCY complaints do you receive a year regarding your activities on your distribution lines?

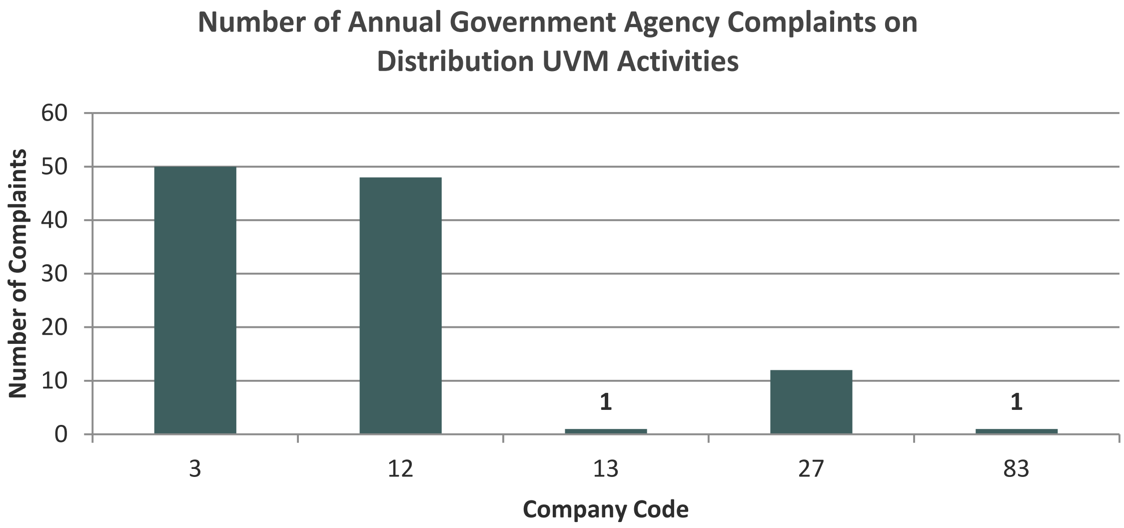

Figure 201: Number of Annual Government Agency Complaints on Distribution UVM Activities

Types of Complaints Received by Government Agencies

Question #168: Please identify the typical types of complaints you receive from local, state or federal Government AGENCIES. Please check all that apply.

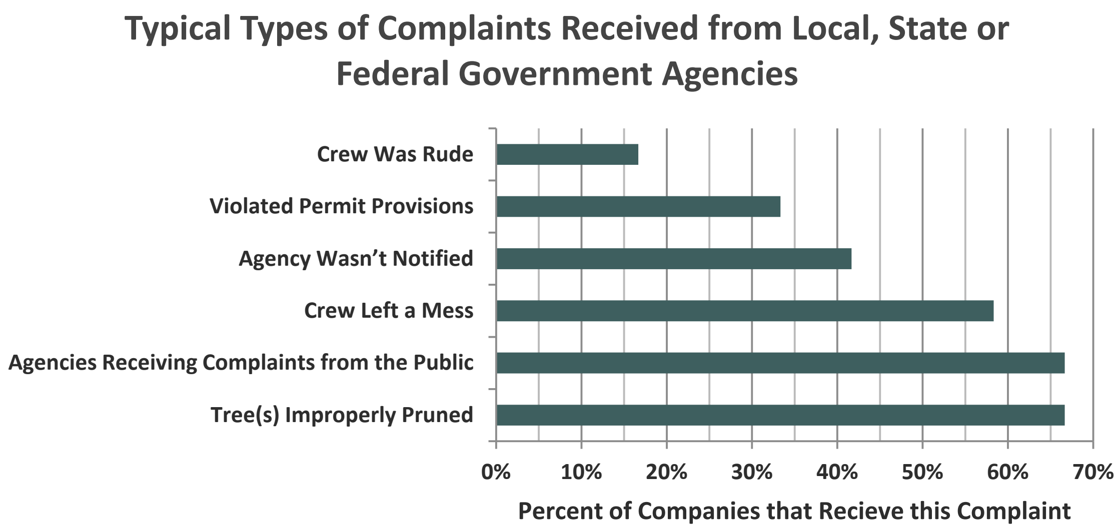

Figure 202: Typical Types of Complaints Received from Local, State or Federal Government Agencies

Relationship with Government Agencies

Question #169: Overall, how would you characterize your relationship with the majority of local, state or federal Government agencies you work with?

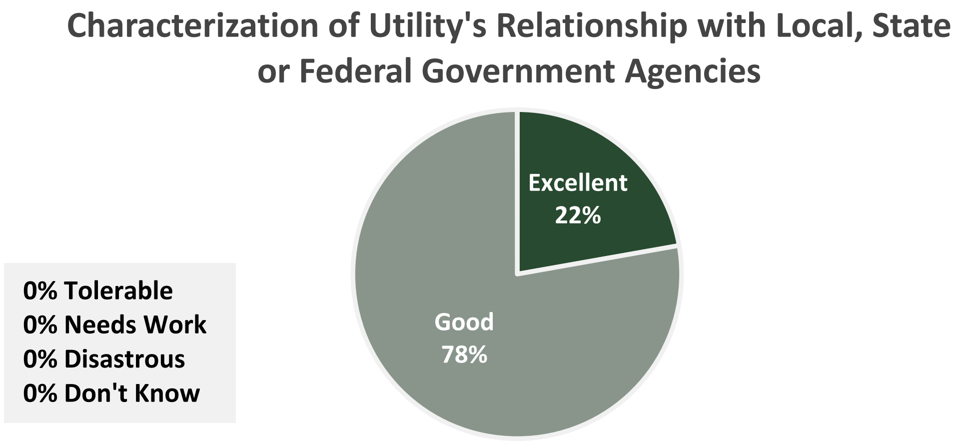

Figure 203: Characterization of Utility's Relationship with Local, State or Federal Government Agencies

Comments on Relationships with Government Agencies
Environmental agencies are particularly difficult to deal with.
Nearby excellent

Figure 204: Comments on Relationships with Government Agencies

Government Agencies Actively Involved in Distribution UVM

Question #170: Which Agencies do you actively work with regarding your vegetation management programs? Please check all that apply.

Comments and Other Government Agencies Actively Involved with UVM
[State] Coastal Commission; [State] Farm Bureau; Firesafe Councils; Numerous local community groups.
Tribal entities.

Figure 205: Comments and Other Government Agencies Actively Involved with UVM

Refer to graph on next page.

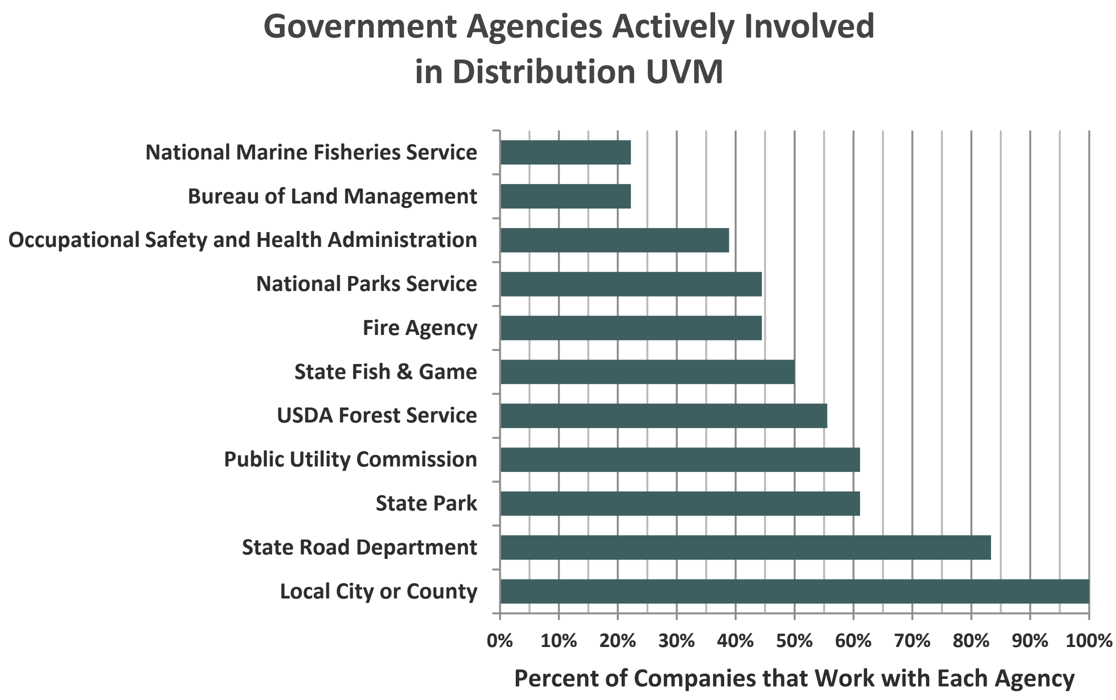

Figure 206: Government Agencies Actively Involved in Distribution UVM

Problematic Government Agencies

Question #171: Who is your MOST difficult local, state or federal Government agency to work with? Please check one only.

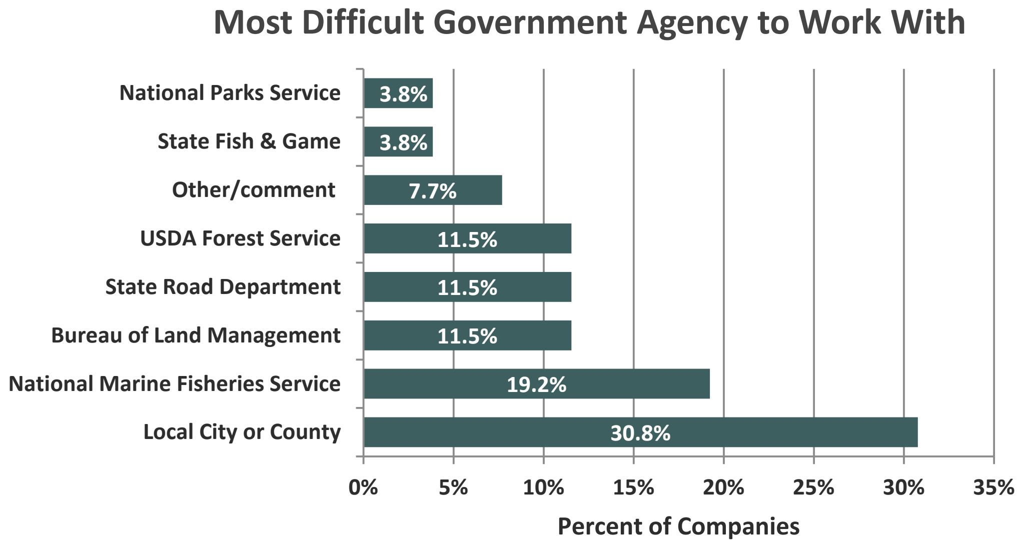

Figure 207: Most Difficult Government Agency to Work With

Comments and Other Agencies that are the MOST Difficult to Work With
None are difficult to work with. We just do what they tell us if we have any interaction with them at all.
Ministry of natural resources.   Most difficult but not extremely difficult.

Figure 208: Comments and Other Agencies that are the MOST Difficult to Work With

ESTABLISHMENT OF 'RIGHT TREE-RIGHT PLACE" INTO EXISTING CODES

Question #172:

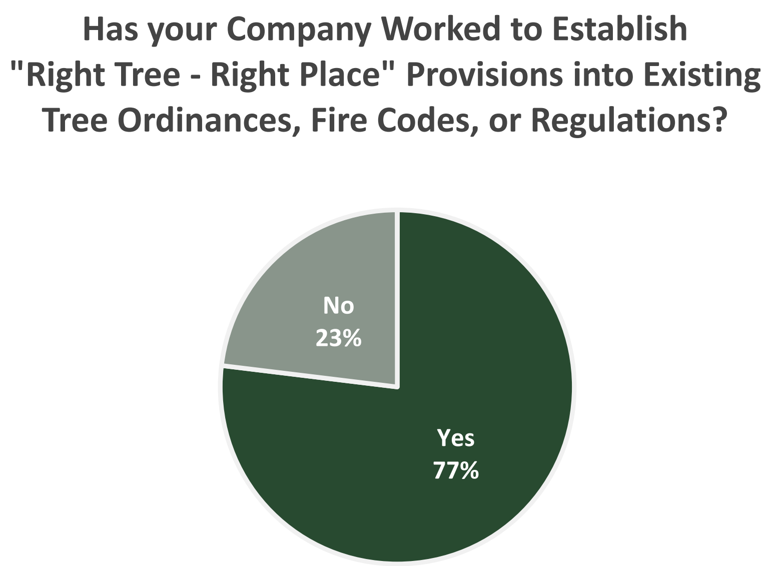

Figure 209: Establishment of 'Right Tree-Right Place" into Existing codes

Comments on "Right Tree- Right Place" Provisions
We work with cities concerning tree ordinances. "Know before you grow" program. [Answered: **Yes**]
Not always well received. Often local politicians have other agendas. [Answered: **Yes**]
No tree ordinances, fire codes, etc. [Answered: **No**]
However, the Ordinances are weakly worded and limited to ROW. [Answered: **Yes**]
It is an important program for us. It's more oriented toward municipality or customers. We've tried to have that program integrated in tree ordinances, but do not succeed. [Answered: **Yes**]

Figure 210: Comments on "Right Tree- Right Place" Provisions

UTILITY TRACKING OF PROPOSED UVM-RELATED LEGISLATION

Question #173:

Does your Company Routinely Track New or Proposed Legislation that Could Impact your Utility Vegetation Management Program?

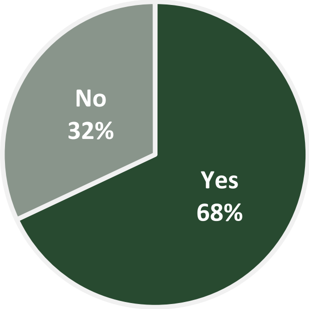

Figure 211: Utility Tracking of Proposed UVM-Related Legislation

Comments on New Legislation Impacting Distribution UVM
Pending [Answered: No]
Municipal Biomass (Tree/Vegetation) Retention Bylaws [Answered: Yes]
Mandatory regulatory and executive management[Answered: No]
Any new or additional changes to clearing, reliability or regulatory standards. [Answered: Yes]
We have a department specializing in government relations. [This department] follows any new law or legislation that could affect our business. UVM is only one of the different topics involved. [Answered: Yes]

Figure 212: Comments on New Legislation Impacting Distribution UVM

PARTICIPANT DESIRED STANDARDS REGARDING UVM

Question #174:

Do You Think There Should Be New Laws or Regulations that Could Assist The Utility Arborist in Any Aspect of UVM Operations?

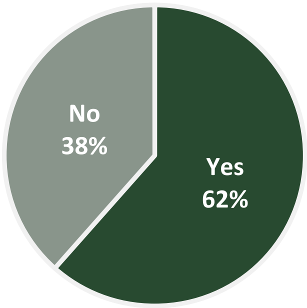

Figure 213: Participant Desired Regulations Regarding UVM

Question #174 (continued): If yes, what should the standard say and is there a current standard, such as ANSI Z133.1 or ANSI A300 that it should fall under?

Participant Desired Standards Regarding UVM
Create a "Public Utility Specialist" license - a sub-category for State Arborist license. Allowing person to declare a utility veg. emergency condition - mitigate as necessary with tree owner notification.
Legislation supporting utilities and criminal offense for stopping line clearance work.
OPUC should adopt language similar, major woody stem exemption. CPUC – Major Woody Stem exemption [Language in place already].
Regulations should ascribe more responsibility and ownership to property owners for the maintenance of their trees and the impact to the company for allowing these conditions to persist.
If a law or regulation could clarify and strengthen our role and rights to conduct vegetation management on a land owner's property we could better control our non-compliant vegetation.
Mandates tend leave little room for common sense
We need a standard to address the landowners' landright issues. Should fall under ANSI Z133.5
That standard must say that tree owners should be responsible of their trees. If a utility has to work on their tree they should be billed for that. It's about public interest.
It should fall under ANSI Z133.1 or ANZI A300 because these are already established and known throughout the utility industry.

Figure 214: Participant Desired Standards Regarding UVM

UVM FUNDING

DESCRIPTION OF UVM BUDGET DERIVATIONS

Question #175: Describe the process used to derive a budget for vegetation management for the distribution system.

Description of UVM Budget Derivations
Annual work types (miles, units, MHs, etc) are tracked. Coming budget based on 2 or 3 year historical average.
An annual list of circuits is assembled based on scheduled maintenance cycle, reliability performance, work logistics. An estimate is derived for each circuit from: 1) Previous cycle cost, 2) Predicted workload increase/decrease (tree in-growth, circuit on or off cycle, previous cycle removal rate), 3) Contractor rate increases since previous cycle.
Start with what we think it would cost to get on a four year cycle. Start with backbone circuits and try to work in multiphase laterals.
Our budget is created by the [State] Public Utilities Commission in what's called a "rate case". Every 3 or 4 years the Commission determines the funding level for our vegetation management program and this amount is fixed for the term of the rate case (either 3 or 4 years, typically 3 years). Any under spent funds are refunded to our customers, over-spending is charged to [Utility's] shareholders.
We make calculations on our cost [per] mile and base our budget request on those figures.
Workload inventories are gathered and a budget is determined. This is typically for a multi-year (2-3) budget submission.
Budget is derived by determining what feeders and laterals are due on cycle and requested funding to address. Other activities are based on 3 year average cost. VM also requests funding on special projects outside of established programs. This funding is on a per program basis by weighing cost/reliability impact.
This is an annual business planning process: 1) Analysis is conducted to define the vegetation management needs for the next 5 years; 2) A maintenance program is developed to satisfy the UVM needs; 3) A high level estimate is generated to price the annual programs; 4) The plan is stakeholdered internally with senior management and our internal service provider; 5) Final budget is derived through a compromise between UVM needs, resourceability and budget restraints.
We try to give the budget personnel the goals that are not being met, including reliability and safety, and then try to set a dollar amount that we need to achieve the goals. It has not worked real well in the past.
Budget is allocated based on overall Corporate earnings target for the year. Depends heavily on company's financial performance at any given time.
The budget is proposed to the VP management and is approved by the board
We deposited a file argument which includes in our global tariff cause at [Government] Energy Board. We estimated our workload accordingly to the cycle we want to reach and maintain.
We submit what our target budget should be to cover all danger tree programs/Skylining Projects (Capital Budget) as well as our needs to cover pro-active line maintenance and reactive programs (O&M budget) to maintain reliability and cycle targets.

Figure 215: Description of UVM Budget Derivations

VARIABLES THAT EFFECT ANNUAL DISTRIBUTION BUDGET

Question #176: The annual budget for distribution vegetation management is primarily influenced by the following variables. Rank the importance of each of these influences on the budget by selecting one of the four categories for each variable. One answer per row

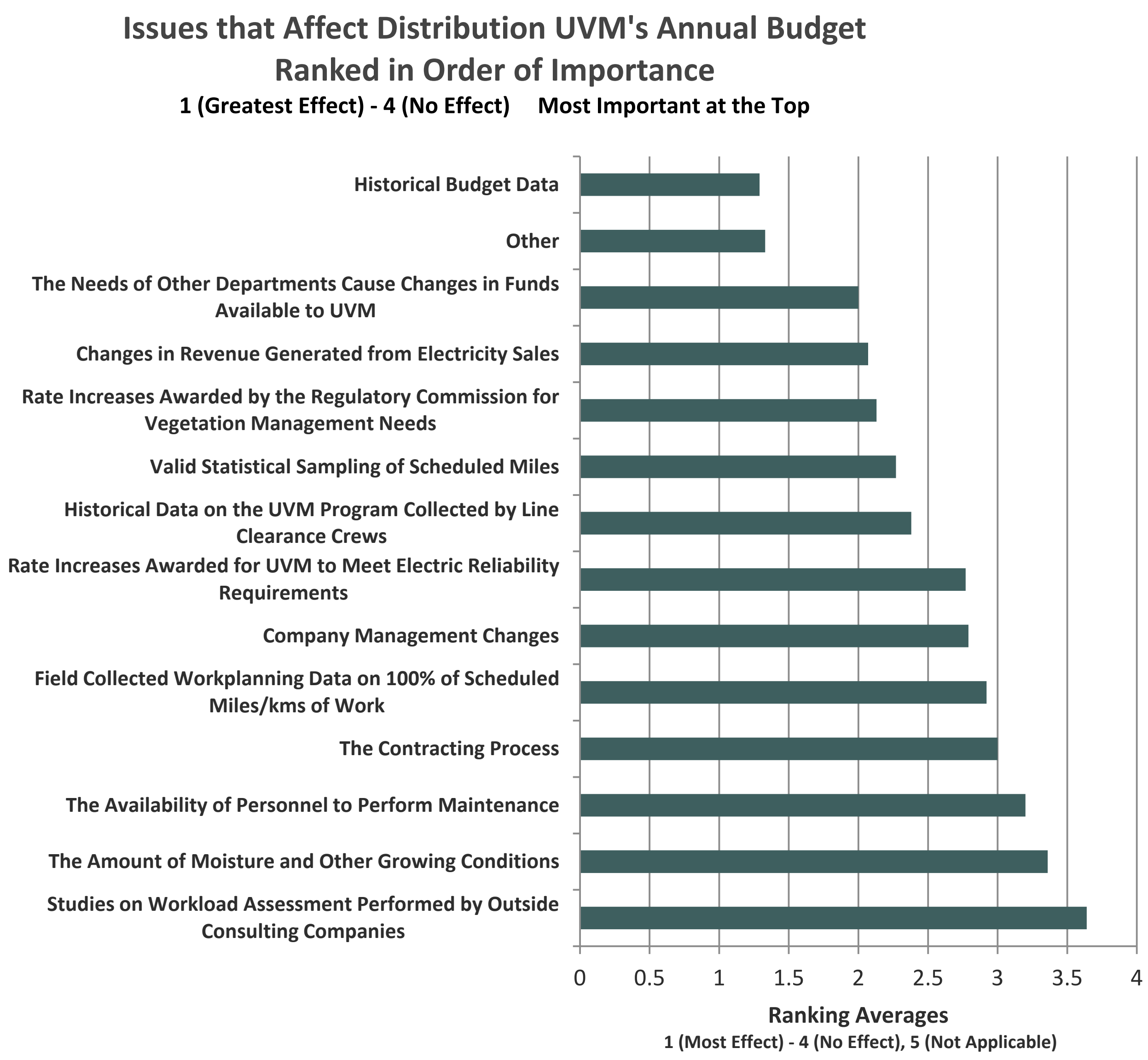

Figure 216: Issues that Affect Distribution UVM's Annual Budget Ranked in Order of Importance

Other Issues Affecting Annual Distribution UVM Budgets
SAIDI and SAIFI
Pruning and brush cutting history
Utility Commission rulings

Figure 217: Other Issues Affecting Annual UVM Budgets

ADEQUACY OF DISTRIBUTION UVM BUDGET TO MEET OBJECTIVES

Adequacy of Budget in the Last Five Years

Question #177: The following statement best describes my budgets of the past 5 years. One answer only.

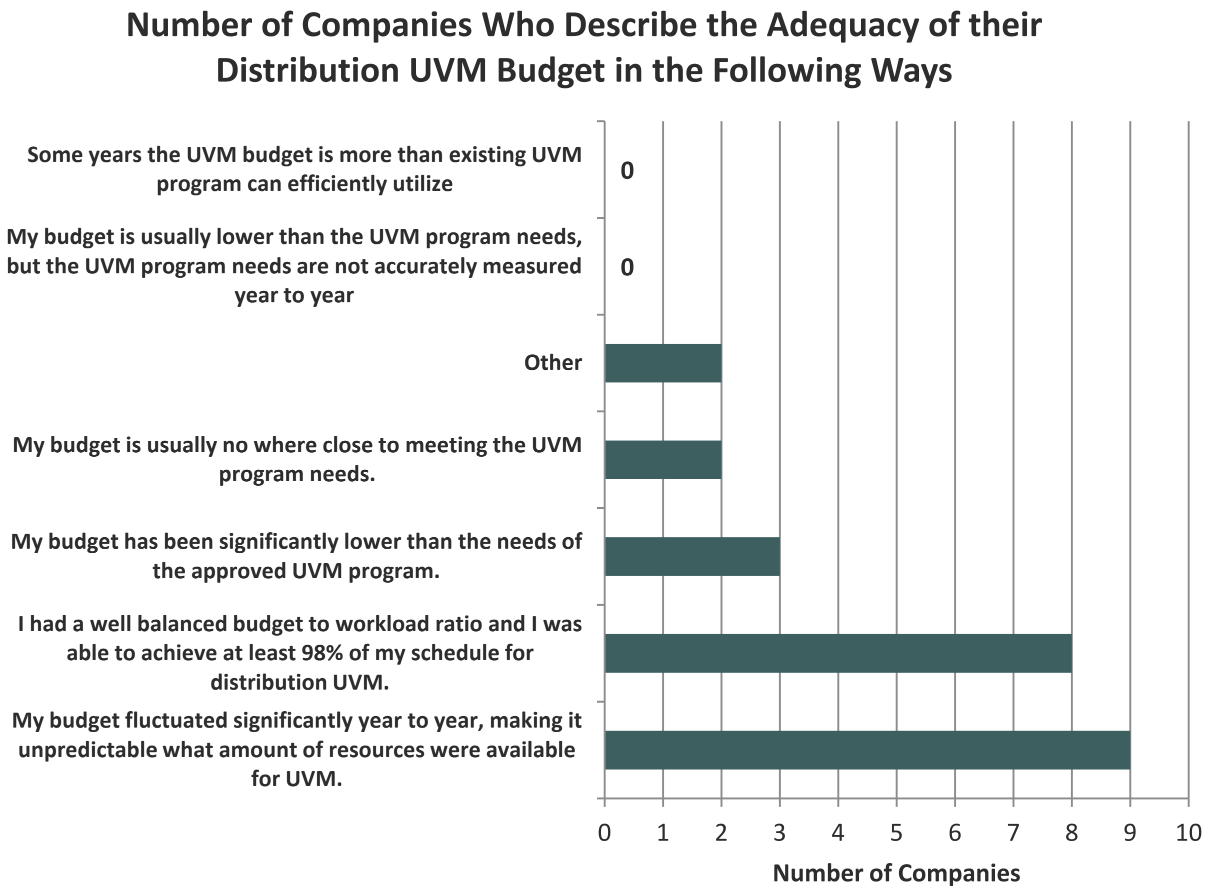

Figure 218: Number of Companies Who Describe the Adequacy of their Distribution UVM Budget in the Following Ways

Comments on Adequacy of the UVM Budget
The budget has been fairly static the past few years but allows at least 90% of schedule.
Our budget has been about 85 - 90% of what is required. We have received budget approval to address acquired backlog.

Figure 219: Comments on Adequacy of the UVM Budget

The following graph derived from data from previous question (<u>**Question #177**</u>)

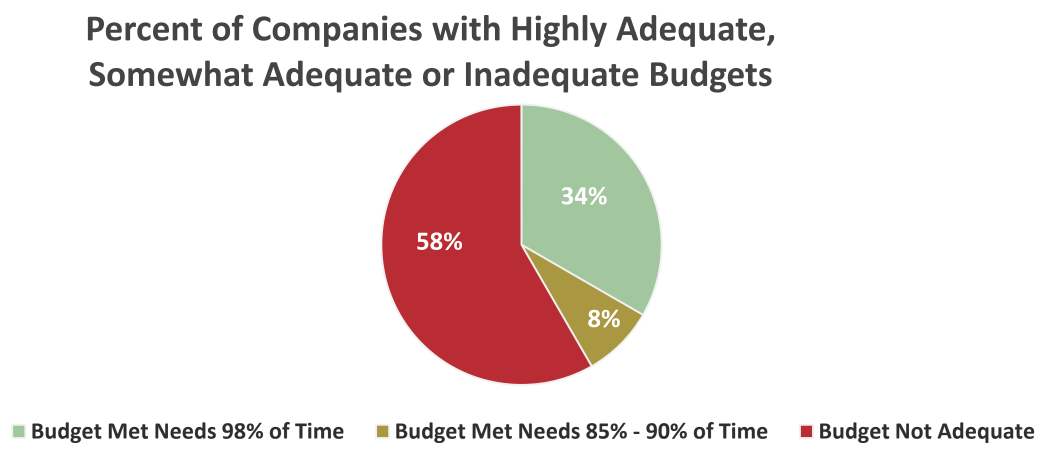

Figure 220: Percent of Companies with Highly Adequate, Somewhat Adequate or Inadequate Budgets

CAPITALIZATION OF UTILITY VEGETATION MAINTENANCE

Possible ways to increase the ability of funding to meet workload would be capitalization of work.

Capitalized Projects

In previous benchmarks we learned that utilities vary in how some work types are included in the UVM budget and others are covered under different budgets and possibly capitalized.

Question #178: Please match the following work types to the type of funding that pays for the work. If there are other UVM work types funded outside the annual UVM budget, please explain in the comments. NOTE: Check all responses that apply to each UVM activity.

Data Discussion of Capitalization of UVM Activities

Funding for UVM Projects (next page) breaks down the sources of UVM funding. Percent of respondents that capitalized a given project (teal and gold on the graph) is greatest for new construction. It can be noted that for the nine categories with any capitalization (bottom nine categories shown on graph, next page); the majority of them are internal company projects or UVM reliability projects (e.g. bottom 5 categories are all internal projects). It is interesting that some projects are not capitalized by any utilities, such *as Hauling Chips and Wood for Bio-Products and Generation, City Tree Programs* and *Tree Planting Projects*. These areas include possible assets to the UVM program, but are not being utilized for alleviating the constraints of UVM budgets. The only program that has any funding from grants is *Smart Grid Projects*. The fact that many activities are paid for by other departments and/or UVM resources are used to perform non-routine activities may add to the previously identified problem of shortfalls in UVM budgets/resources.

Data collected from **Question #178** See ***Data Discussion of Capitalization of UVM Activities*** for analysis of following graph (Figure 220).

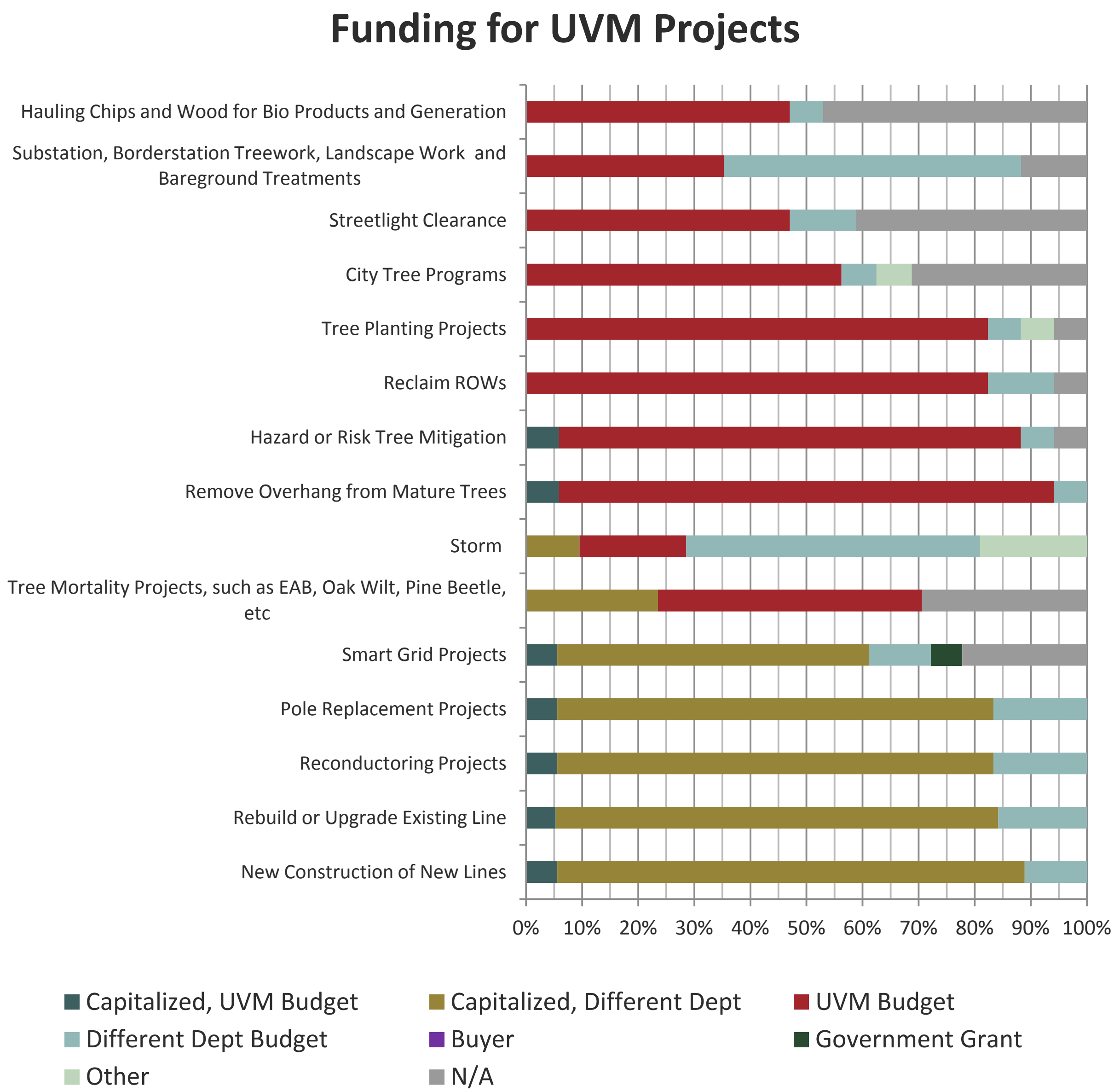

Figure 221: Funding for UVM Projects

"Other" Funding Sources on *Funding Sources for UVM Budgets* Graph
If a storm is formally declared a disaster area by officials, [Utility] is allowed to recover these costs through a special application to the Public Utilities Commission.
Specified Storm account
Same Dept different budget [for storm]

Figure 222: "Other" Funding Sources on *Funding Sources for UVM Budgets* Graph

THE EFFECTS OF RELIABILITY MEASUREMENTS ON UVM

COLLECTION OF RELIABILITY METRICS

Before making comparisons of tree-related reliability metrics (SAIDI, SAIFI, CAIDI, etc.) between utilities, CN Utility Consulting would like to look at the tracking procedures used by the benchmark participants that reported these metrics. When compiling the data for the graphs that follow, it was discovered that there are differences in the ways companies define sustained outages and major events. Since data collection is inconsistent between companies, it is important to note that comparisons are questionable. Unfortunately, it is impossible to normalize the data, since the assumptions for reliability are completely different between companies (i.e. the application of IEEE 1366-2003 is at best only applied in more recent years and at worst not used according to all of its rules. Plus IEEE-1366-2003 has its own problems with capturing an accurate picture of reliability for UVM).

Question #179:

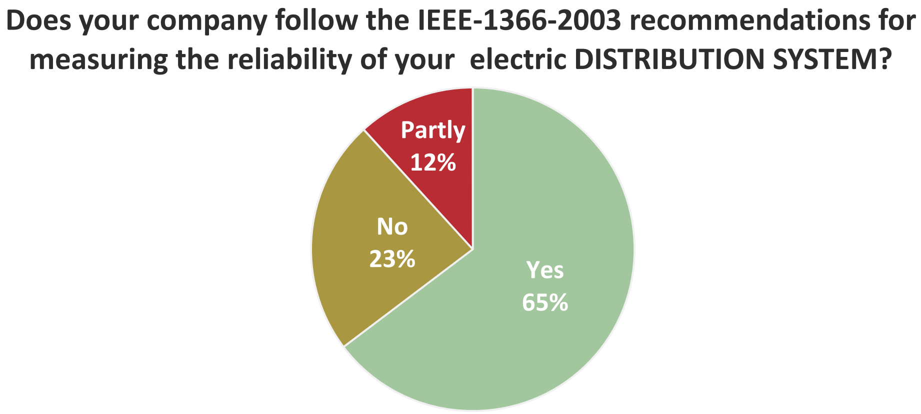

Figure 223: Reliability Metrics Collected by Using IEEE-1366-2003

Comments on Definitions Used for the Collection of Reliability Metrics
We use the IEEE-1366-2003 recommendations when participating in the IEEE Survey. [ANS: “Partly”]
Outage > 1 minute [ANS: “No”]
We have our own standard that we use. We compare ours to IEEE 1336-2003 for validation of our results. We measure "All Events" and "Normalized (excluding major events)" [ANS: “Partly”]
We use [State] Public Service Commission ("FPSC" Hence Forth) Guidelines [ANS: “No”]
Please see paper "Investigation of the 2.5 Beta Methodology" at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5762382 and paper "Major Event Day Segmentation" **http://ieeexplore.ieee.org/application/enterprise/entconfirmation.jsp?arnumber=1664988** [ANS: “No”]
The previous IEEE standard is used (10% of customers affected, storm duration > 24 hours) [ANS: “No”]

Figure 224: Comments on Definitions Used for the Collection of Reliability Metrics

RELIABILITY METRICS USED BY INDUSTRY

Question #180: Which of the following measurements does your company use to understand and report on reliability? Which are used to evaluate the UVM program? Check all that apply.

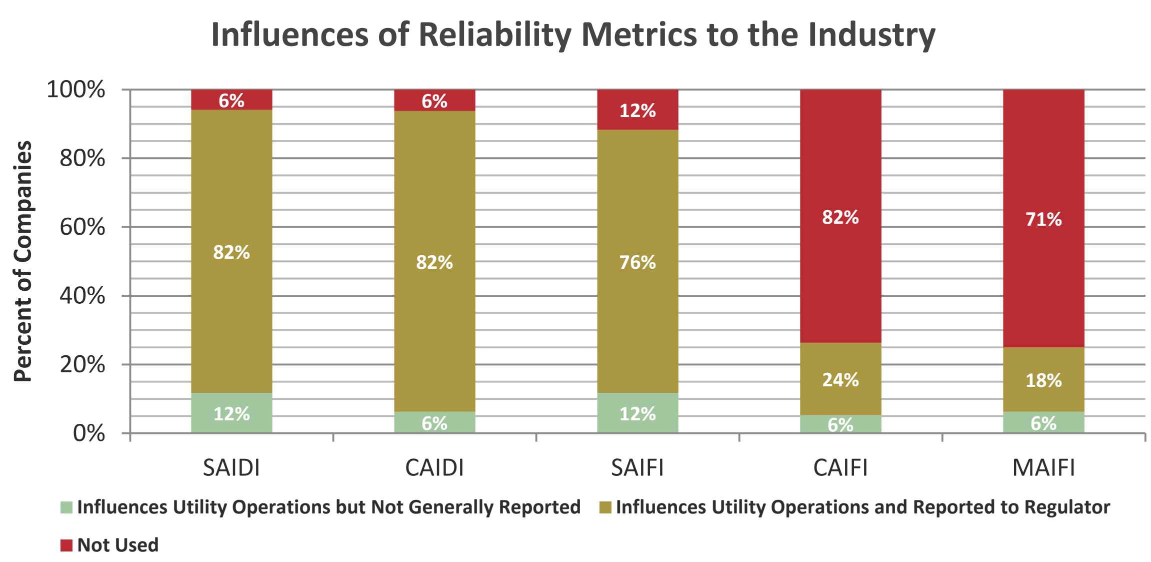

Figure 225: Influences of Reliability Metrics to the Industry

The graph above has the most influential reliability metric (SAIDI) on the left of the chart and the influence decreases as you move right. In contrast, the graph below shows that SAIFI rather than SAIDI is used for UVM by the majority companies responding. The difference between how many companies use SAIFI compared to SAIDI is 18%. It should be noted that many companies use more than one metric for UVM.

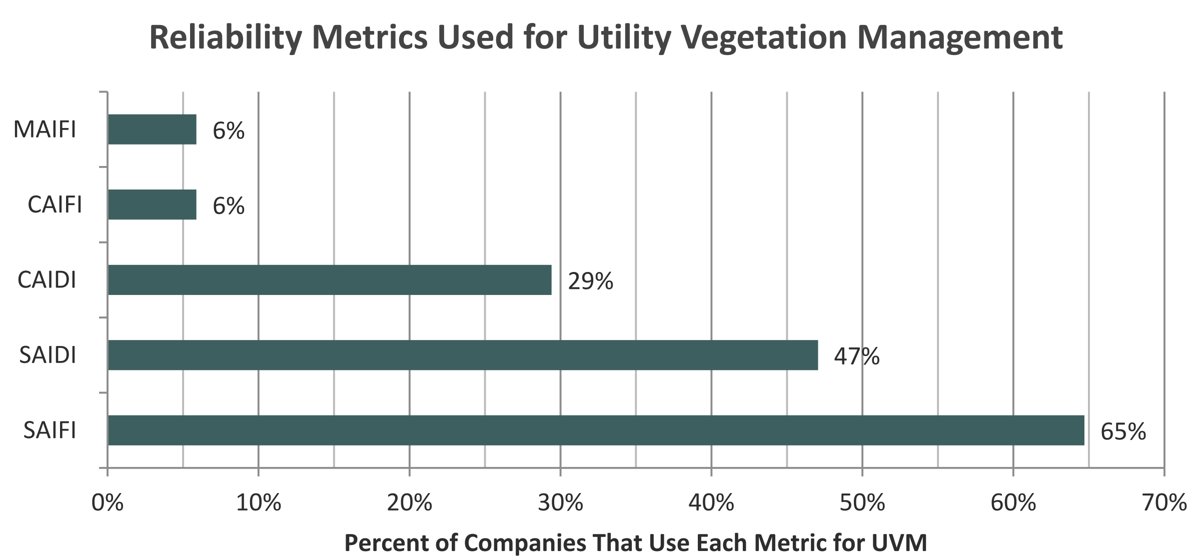

Figure 226: Reliability Metrics Used for Utility Vegetation Management

DEFINING MAJOR EVENTS

Question #181:

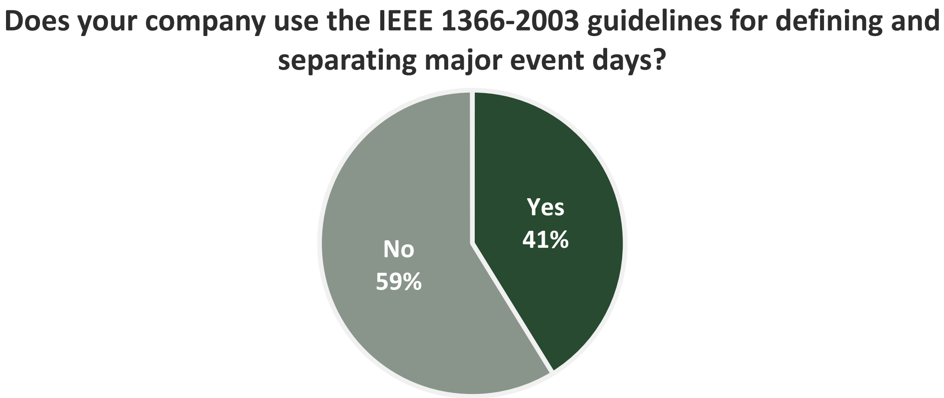

Figure 227: Defining Major Events

T-Meds from Respondents That Use IEE 1366-2003 Guidelines for Major Event
[T-Med is] 4.32 [Note: This is less than 5 minutes. > 5 minutes is the defined length of time for a sustained outage according to IEEE 1366-2003][1]
[T-Med is] 2.5 Beta Method
For 2010 [T-Med] was 4.12 minutes [Note: This is less than 5 minutes. > 5 minutes is the defined length of time for a sustained outage according to IEEE 1366-2003][2]
[T-Med is] 6.8

Figure 228: Comments from Respondents That Use IEE 1366-2003 Guidelines for Major Event

When just looking at the companies that are using IEEE 1366-2003 (Comment Table above), one can note that the *complete* adoption of the guidelines is not being followed. For example, two of the companies are not defining momentary and sustained outages as prescribed by IEEE 1366-2003. This is obvious by looking at their T-Meds. Since less than 5 minutes is the duration for a momentary outage as defined by IEEE 1366-2003[3] and these two companies have thresholds less than 5 minutes, then they are not actually completely adopting these guidelines. It should also be noted that these guidelines require five year averages. It is questionable whether companies have five years of data that fit the 1366-2003 measurement. Sustained outages have been defined as more than one minute by many or most of the industry. Past measurements used to calculate current T-med may be based on older definitions for sustained outages and major events. It is possible that data collection was done with an older definition of a sustained outage or they have maintained their old definitions while using these guidelines for separating major events.[4]

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[1] Richard E. Brown, *Electric Power Distribution Reliability,* p. 50.

[2] Ibid

[3] Ibid

[4] To complicate this further it should be noted here that 1366-2003 has been revised and a new version was released by IEEE called "P1366/D6 November 2011- Draft."

Question # 182: If you answered "NO" to [using IEEE 1366-2003 Guideline for Major event Days], can you please state how your company defines "storm" event when tracking outages?

Comments from Respondents That Do NOT Use IEEE 1366-2003 Guidelines for Major Events
A major storm is declared when the number of restoration steps exceeds the 98.5 percentile of all days in the most recent four calendar years. All reliability data associated with interruptions beginning on that qualifying day would be considered major storm even if the interruptions extend into subsequent days.
Storm exclusion is set by [if] O&M $ to repair [storm damage] exceeds a pre-set threshold and % of customers outaged for over 24 hours [exceeds pre-set threshold].
We define it as a "Major Event" A Major Event is defined as an uncontrollable event (e.g. windstorm, earthquake, forest fire, flood, lightning etc.) that causes an outage resulting in more than 70,000 customer-hours lost or if customer-hours lost is >=1% of annual customer-hours lost for the distribution system, whichever is less. The definition excludes controllable causes such as equipment failure or human error at the distribution, substation or transmission level.
We use [State] Guidelines Major Event Days are classified as Named Storms, Tornados, ice on lines, or extreme weather or fire, causing Emergency Operations Center ("EOC" Hence Forth) to be opened.
[Utility] Distribution deems a "Major Event' to have occurred when 10% or more of [Utility's] customers have been interrupted by an event. An event may be a storm (usually the case), the August 14, 2003 blackout or any other problems that interrupt 10% or more customers and cause a change in the normal restoration business processes. All [Utility] Distribution customers interrupted throughout the duration of the event while normal restoration business processes are suspended are counted in the determination of the numerator of the percent interrupted. The denominator is the total number of customers served at the end of the month when the force majeure occurred.
Over the years a wide range of methods have been proposed to define major events. One approach that has been provided by the IEEE is the IEEE Standard 1366-2003—2.5 Beta Methodology. According to this methodology, it is only valid if a utility's reliability data completely follows the log-normal distribution, particularly with respect to the tails of the distribution. It has been shown that this is not the case for interruptions in all utilities. Issues arise when the right tail of a utility data set does not fit the log-normal distribution. Also the threshold defined by the IEEE 1366-2003—2.5 Beta Methodology varies since it is dependent on a utility's reliability data from the previous five years. As a result, major events, reflected by a large daily SAIDI value, may cause an unsuitable increase in the threshold for future years and lead to inconsistent segmentation of data. Please see paper "Investigation of the 2.5 Beta Methodology" at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5762382 and paper "Major Event Day Segmentation" at http://ieeexplore.ieee.org/application/enterprise/entconfirmation.jsp?arnumber=1664988
Normally it has to meet certain thresholds to be considered a major event. Our service territory is broken up by regions or networks and if a certain region has 10% or more of its customer base without lights for longer than a 24 hour period, it can be considered a major event. There are some variances that can take place to this formula but normally that is the criteria to be considered a Major event.
After each month is concluded, our performance management group will look at all outage data and determine which events it can classify as "Storm" event based on Customer Interruptions and Customer Minutes. To do so, the "Storm" event will have to meet certain thresholds.
Calculated by each individual REGION and rolled up together.
Number of events per day, by region

Figure 229: Comments from Respondents That Do NOT Use IEE 1366-2003 Guidelines for Major Events

Question #184: If you do NOT follow the IEEE 1366-2003 method for determining Major Events, please describe what outages are EXCLUDED from your company's calculation of SAIDI, SAIFI, CAIDI (e.g. momentary outages, storm etc.).

Comments on Outages Excluded as "Major Events" from Calculations of Reliability Metrics
Major storms are defined in #182, planned and customer caused outages are excluded.
Number of events per day, rather than SAIDI per day (4 companies)
We calculate two sets: with storm, and without storm. All calculations do **not** include outages less than or equal to one minute, planned outages, customer equipment outages that only effect that customer, single customer requested outages, under frequency events, and load shedding events.
Momentary outages (< 1 min.) are excluded.
Major Event Days as stated by the [State PUC], including Named Storms, Tornados, ice on lines, or extreme weather or fire, causing EOC [Emergency Operations Centers] to be opened.
[Utility] included all sustained outages in our system. [Utility] is able to calculate SAIDI/SAIFI/CAIDI by having the data segregated and filtered according to various requirements.

Figure 230: Comments on Outages Excluded as "Major Events" from Calculations of Reliability Metrics

TRACKING RELIABILITY METRICS

Tree-Related Outages

Tracking Tree-Related Outages

Question #185: Do you track tree-related outages?

YES for 100% of respondents

Calculating Tree-Related Reliability Statistics

Question #186:

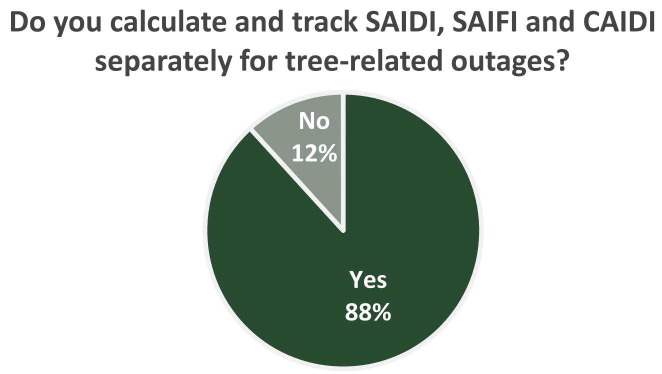


Figure 231: Do You Calculate Tree-Related Reliability Statistics?

Question #187:

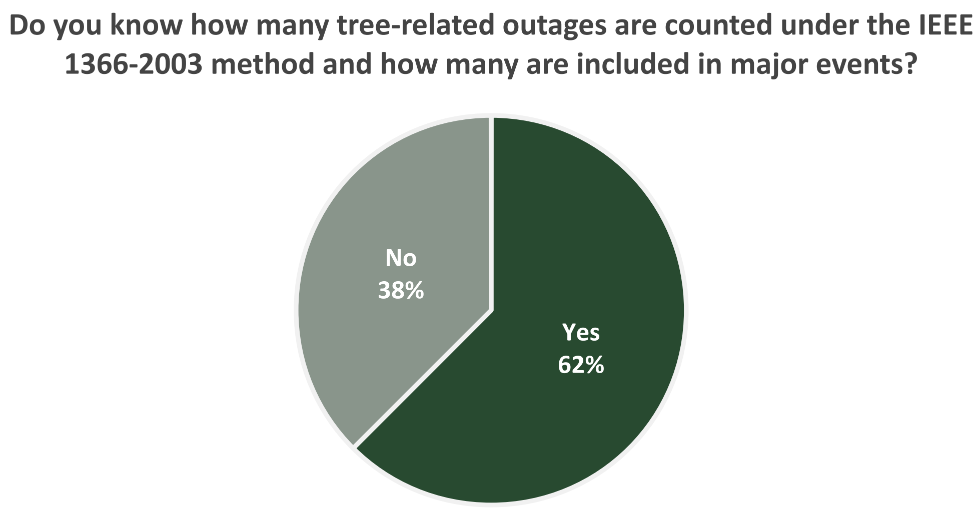


Figure 232: Do You Count Tree-Related Outages Using IEEE 1366-2003 Method?

If you answered "NO", please comment on your methodology
A major storm is declared when the number of restoration steps exceeds the 98.5 percentile of all days in the most recent four calendar years. All reliability data associated with interruptions beginning on that qualifying day would be considered major storm even if the interruptions extend into subsequent days.
The company keeps some of this data but would not provide the resources to pull any reliability data for this survey.
Tree outages are calculated under [State] Guidelines where 1 minute is an interruption; therefore, any tree related interruption >1 minute is counted. We know how many tree outages are counted under [State] Guidelines, and how many are included in Major Events as classified by the [State].
[Utility] included all sustained outages in our system. [Utility] is able to calculate SAIDI/SAIFI/CAIDI by having the data segregated and filtered according to various requirements.
I am not familiar with this.

Figure 233: Comments on Counting Tree-Related Outages

TREE-RELATED OUTAGES

The graphs in this section all were generated using the data collected in question #188 (below).

Question #188: Please provide the NUMBER of UNPLANNED sustained outages your company experienced in the following years on your distribution system CAUSED BY TREES during 'Major Events' and 'Non-Major Events', as defined by IEEE 1366-2003. Also include the total customer minutes lost each year in each category.

NOTE: If you do NOT use IEEE 1366-2003 to define major events, answer the question using your definition of storm event (supplied in question #182).

Graphs from data collected in **Question #188**

Number of Non-Major Unplanned Tree-Related Outages

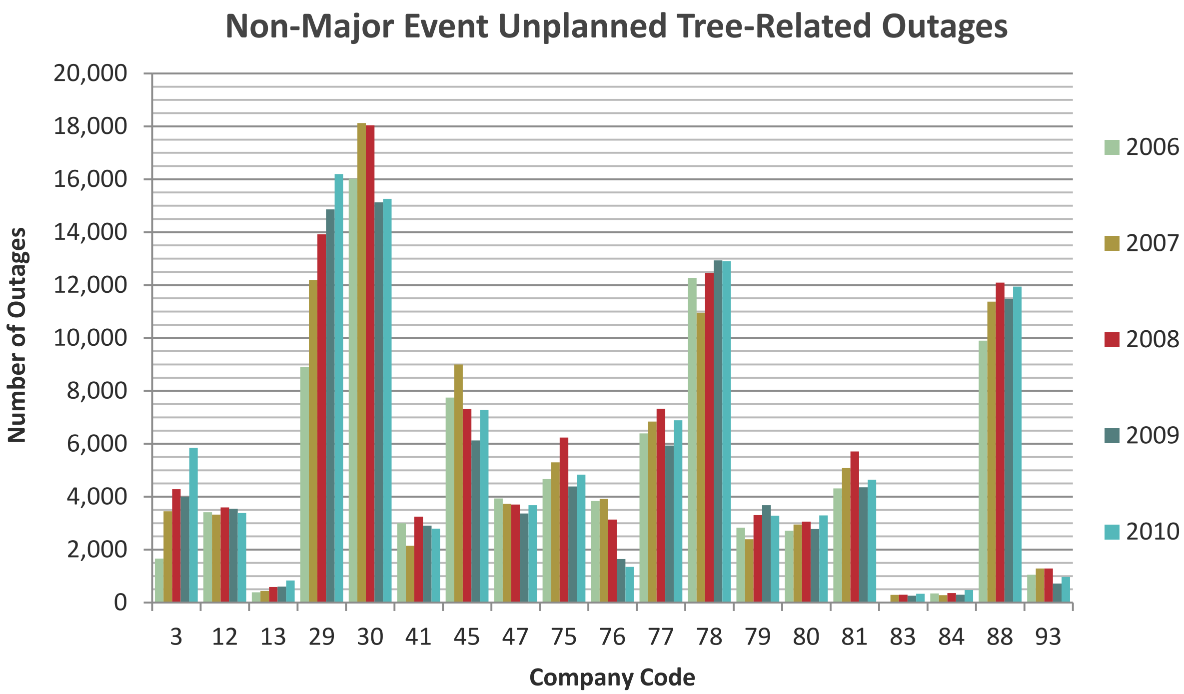


Figure 234: Non-Major Event Unplanned Tree-Related Outages for Years 2006 - 2010

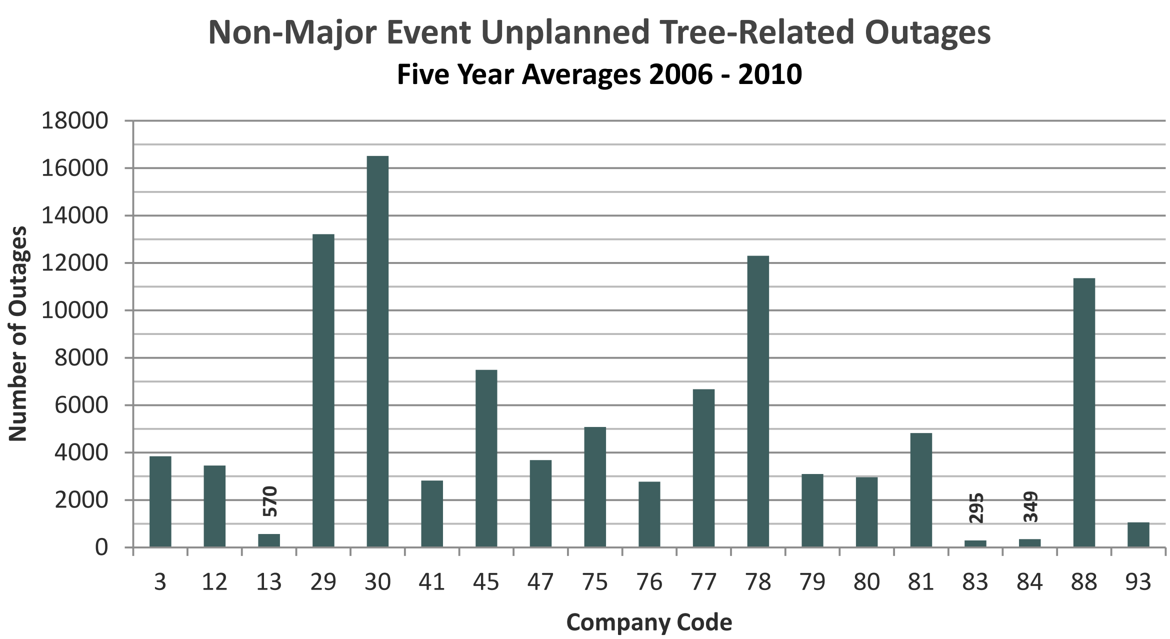


Figure 235: Non-Major Event Unplanned Tree-Related Outages Five Year Averages (2006 – 2010)

Number of Customer Minutes Lost for Non-Major Unplanned Tree-Related Outages

Graphs from data collected in **Question #188**

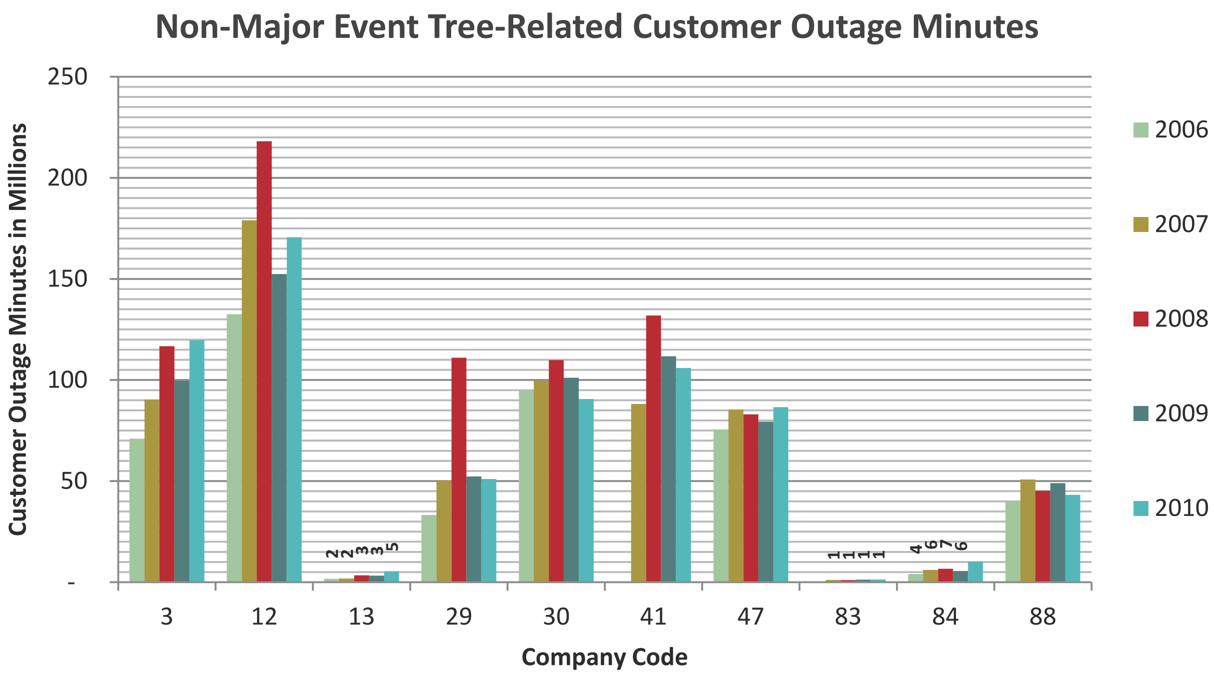


Figure 236: Non-Major Event Tree-Related Customer Outage Minutes for Years 2006 - 2010

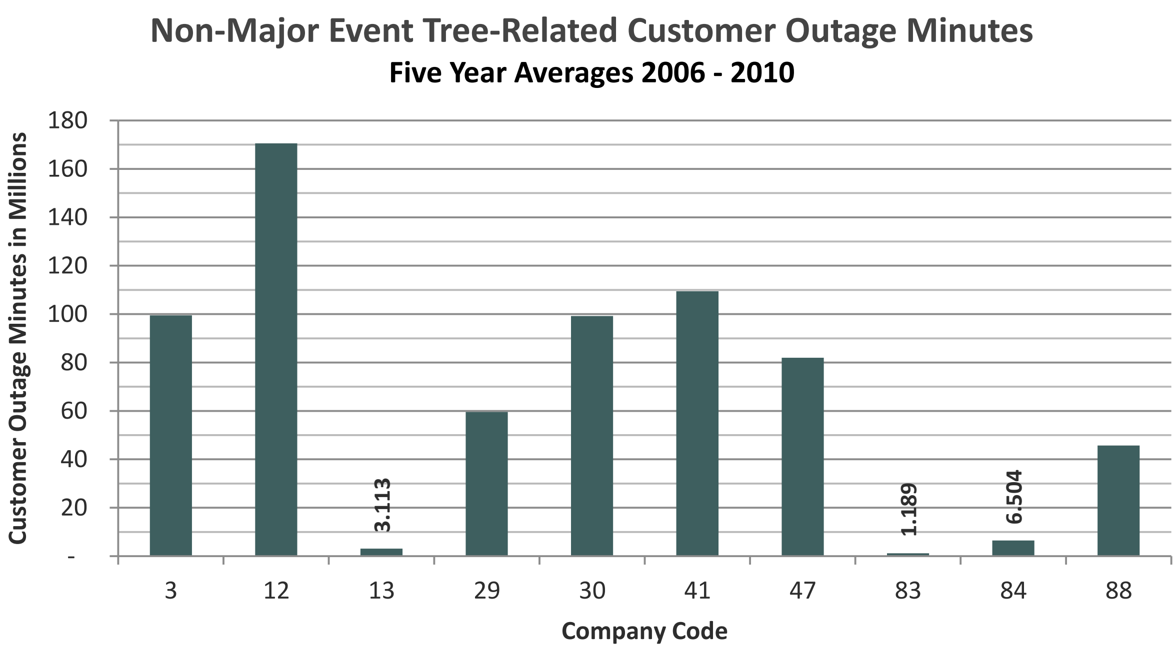


Figure 237: Non-Major Event Tree-Related Customer Outage Minutes Five Year Averages (2006 -2010)

Major Event Tree-Related Outages

Graphs from data collected in **Question #188**

Number of Major Event Unplanned Tree-Related Outages

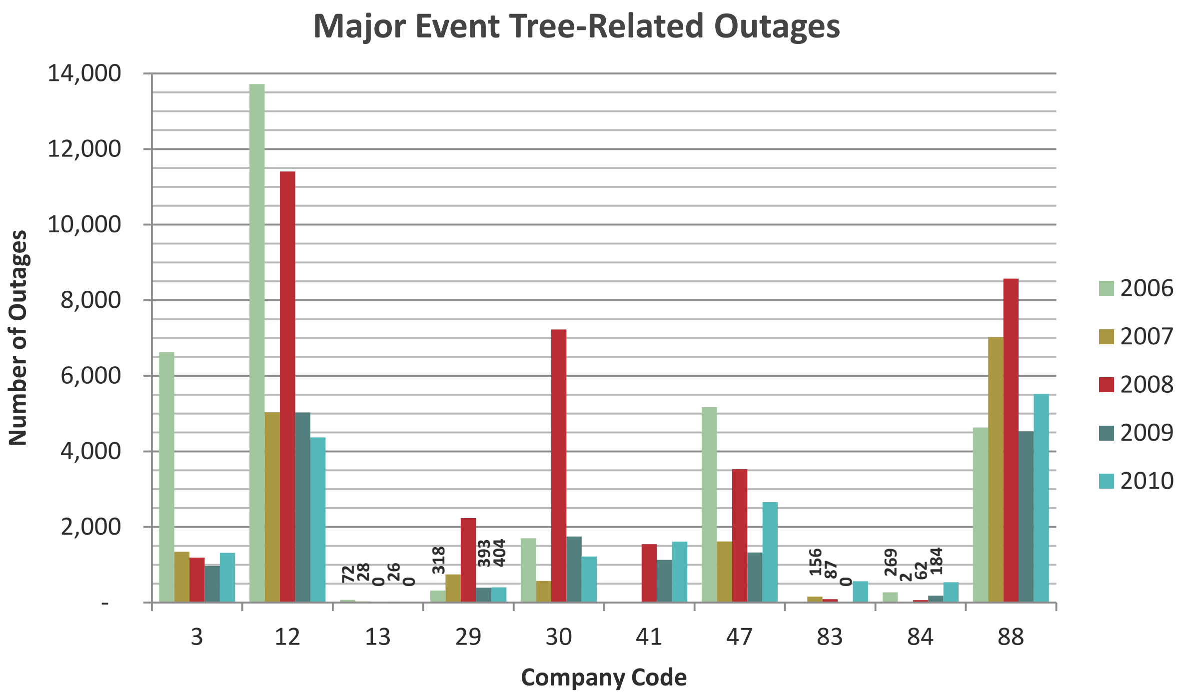


Figure 238: Major Event Tree-Related Outages for Years 2006 - 2010

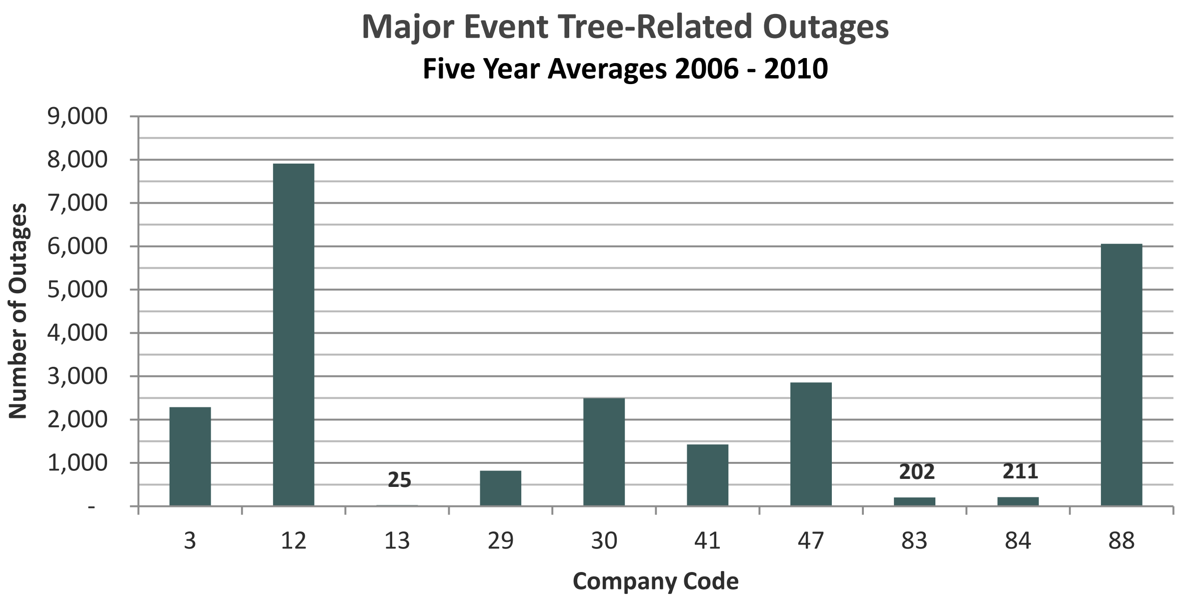


Figure 239: Major Event Tree-Related Outages Five Year Averages (2006 -2010)

Number of Customer Minutes Lost for Major Tree-Related Outages

Graphs from data collected in **Question #188**

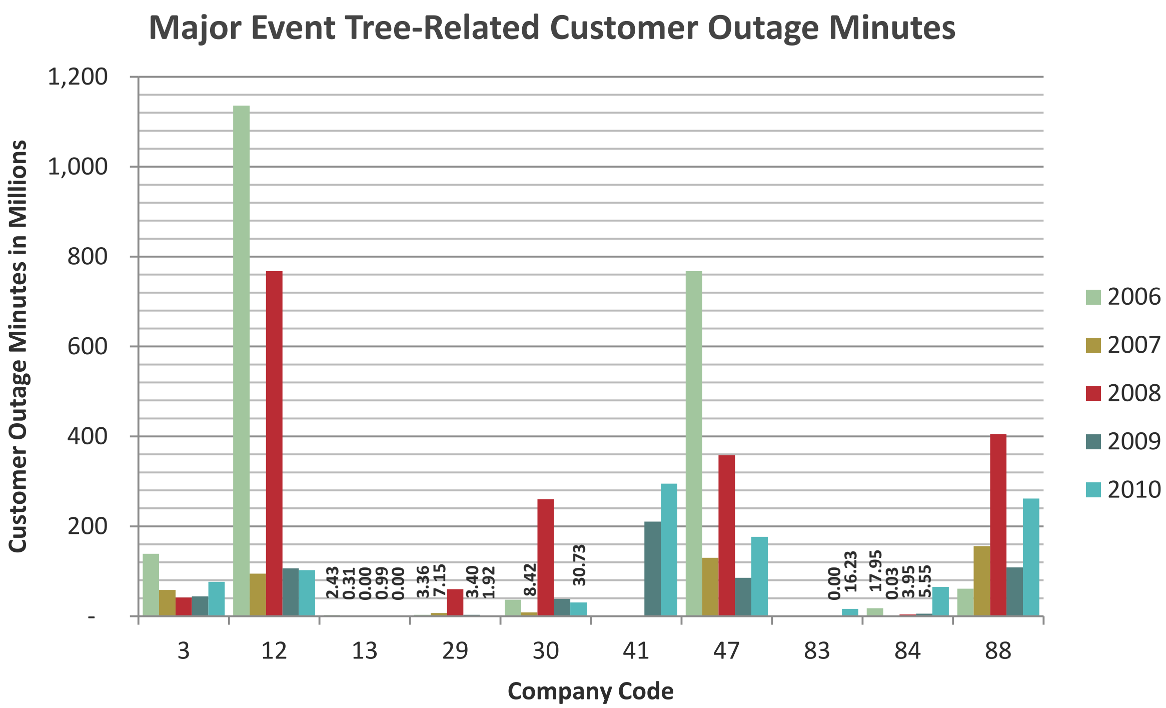


Figure 240: Major Event Tree-Related Total Customer Outage Minutes for Years 2006 - 2010

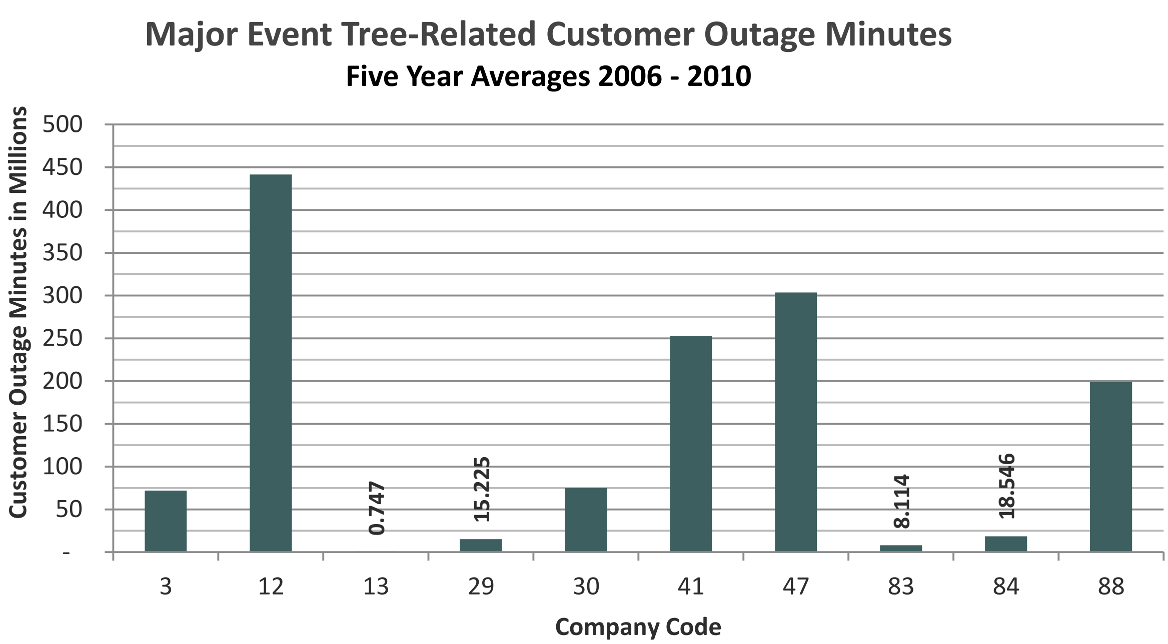


Figure 241: Major Event Tree-Related Customer Outage Minutes Five Year Averages (2006 -2010)

SYSTEM-WIDE RELIABILITY METRICS

System-Wide Non-Major Event SAIDI

Question # 189: What was your company's TOTAL DISTRIBUTION SYSTEM AVERAGE INTERRUPTION INDEX (SAIDI) for IEEE 1366-2003 defined outages for the following years and what is the TOTAL SAIDI FOR MAJOR EVENT/STORM only?

NOTE: If you do not use IEEE 1366-2003 to define major events, answer the question using your definition of storm event (supplied in question #182).

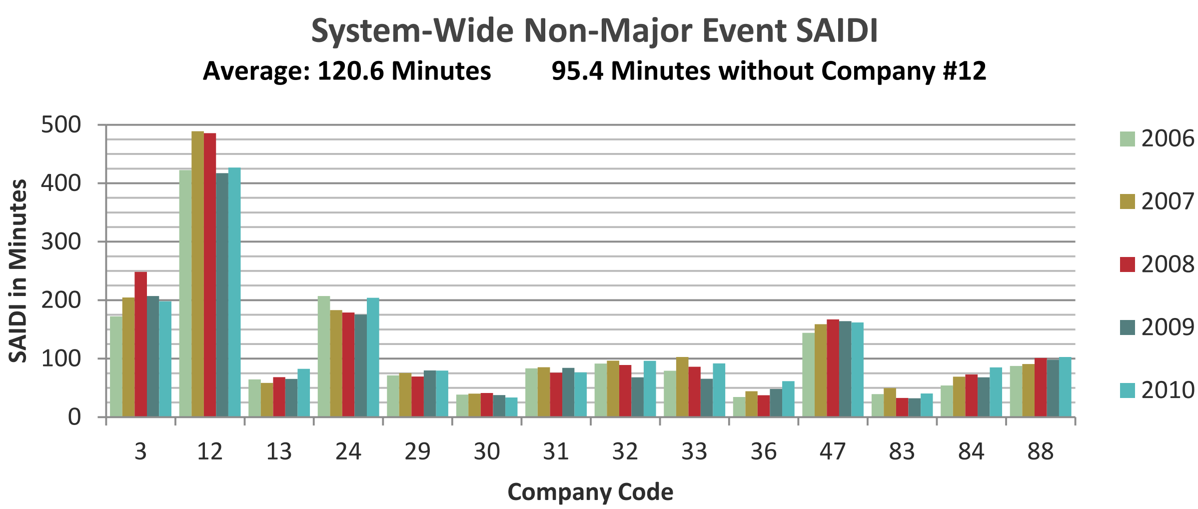


Figure 242: System-Wide Non-Major Event SAIDI for Years 2006 - 2010

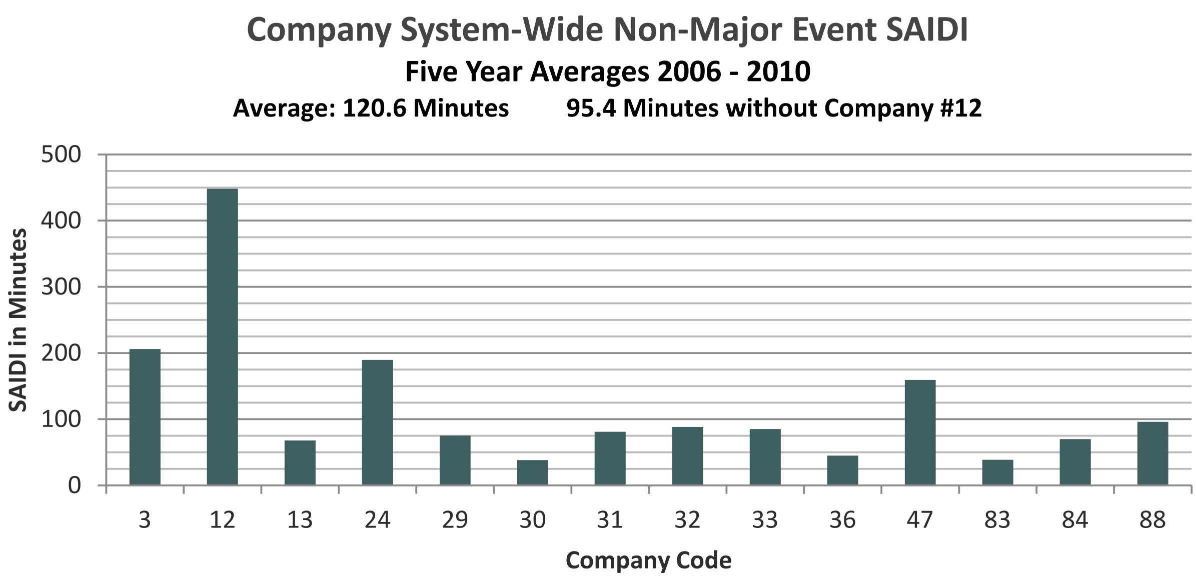


Figure 243: System-Wide Non-Major Event SAIDI Five Year Averages (2006 -2010)

System-Wide Major Event SAIDI

Graphs from data collected in **Question #189**

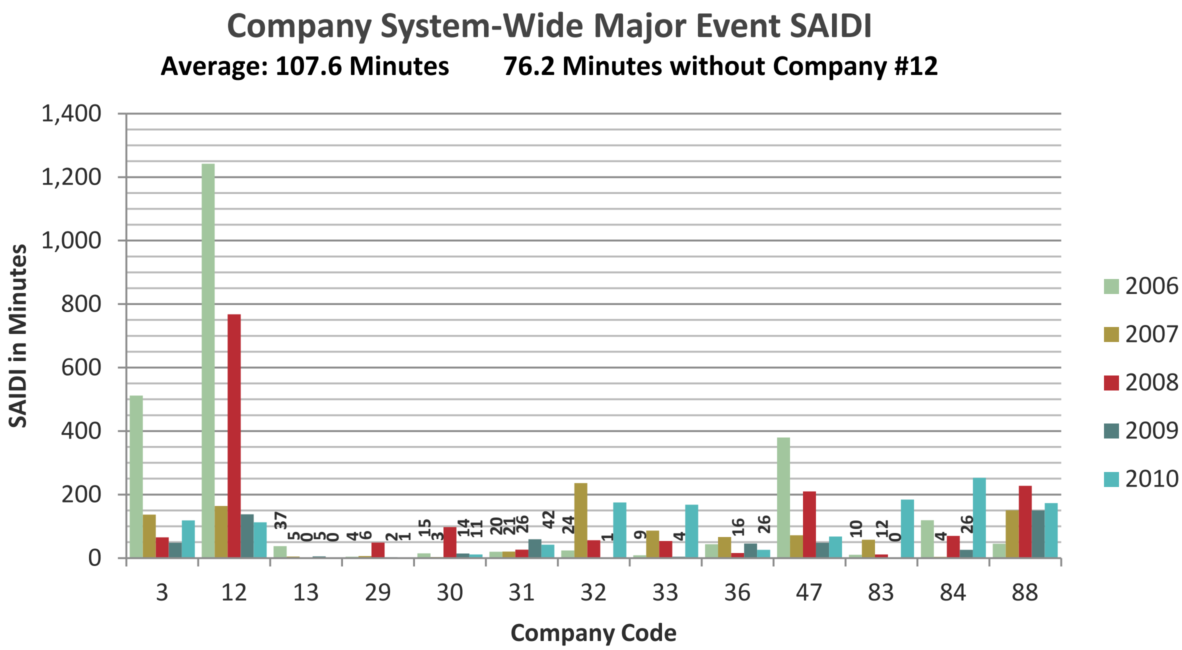


Figure 244: Company System-Wide Major Event SAIDI for Years 2006 - 2010

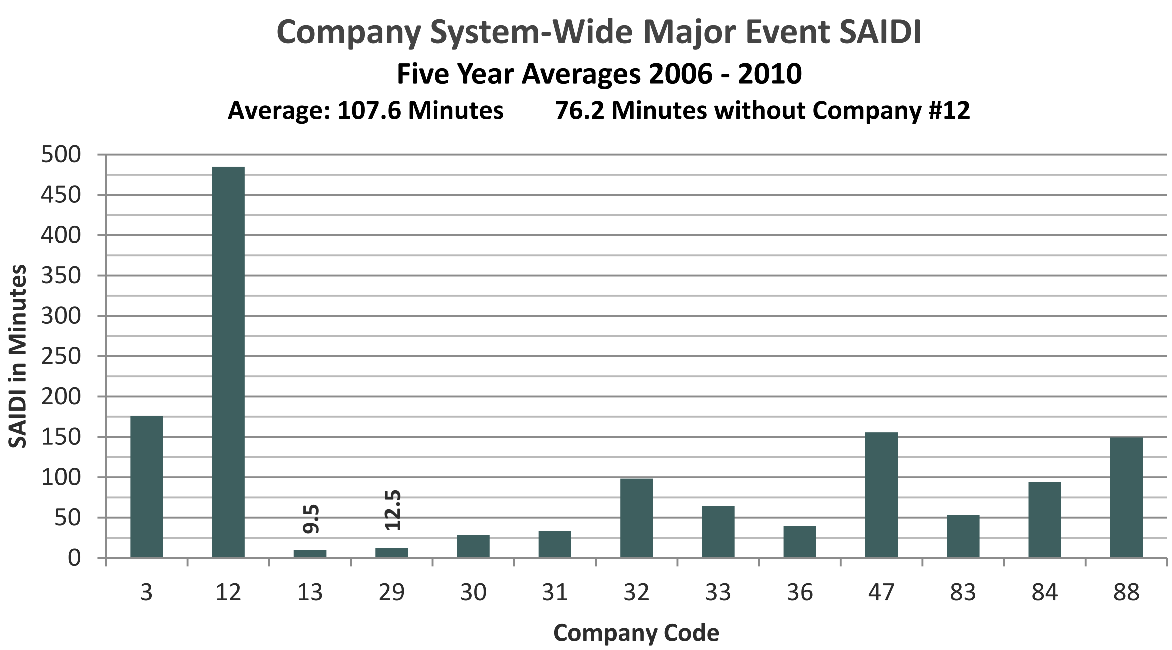


Figure 245: Company System-Wide Major Event SAIDI Five Year Averages (2006 -2010)

System-Wide Non-Major Event SAIFI

Question #190: What was your company's DISTRIBUTION SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI) for IEEE 1366-2003 defined outages for the following years and what is the TOTAL SAIFI FOR MAJOR EVENT/STORM only?

NOTE: If you do not use IEEE 1366-2003 to define major events, answer the question using your definition of storm event (supplied in question #182).

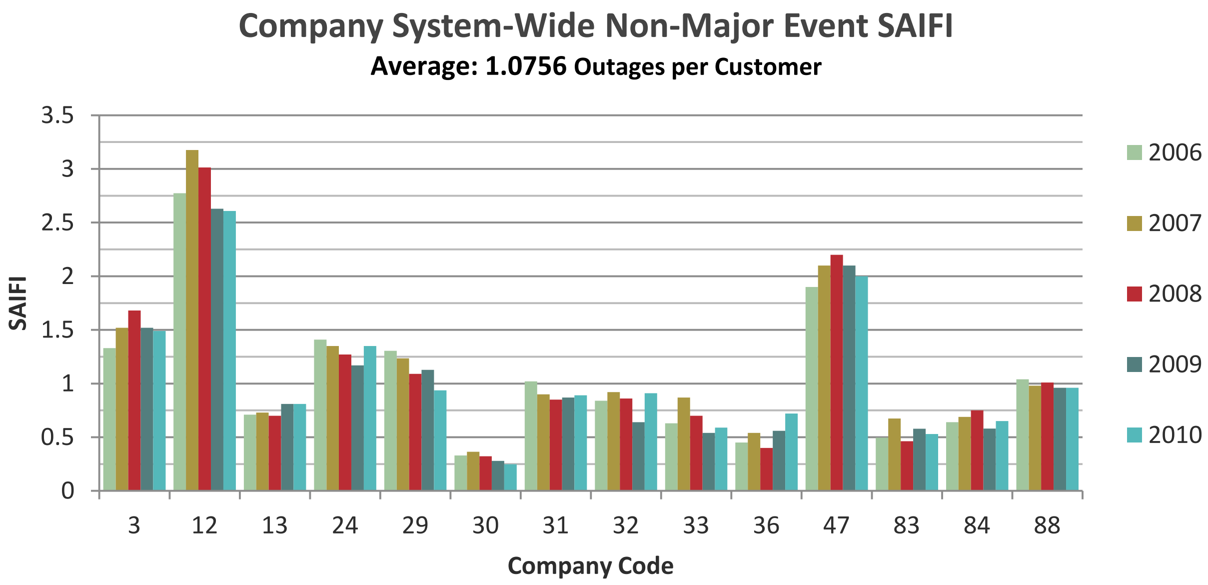


Figure 246: Company System-Wide Non-Major Event SAIFI for Years 2006 - 2010

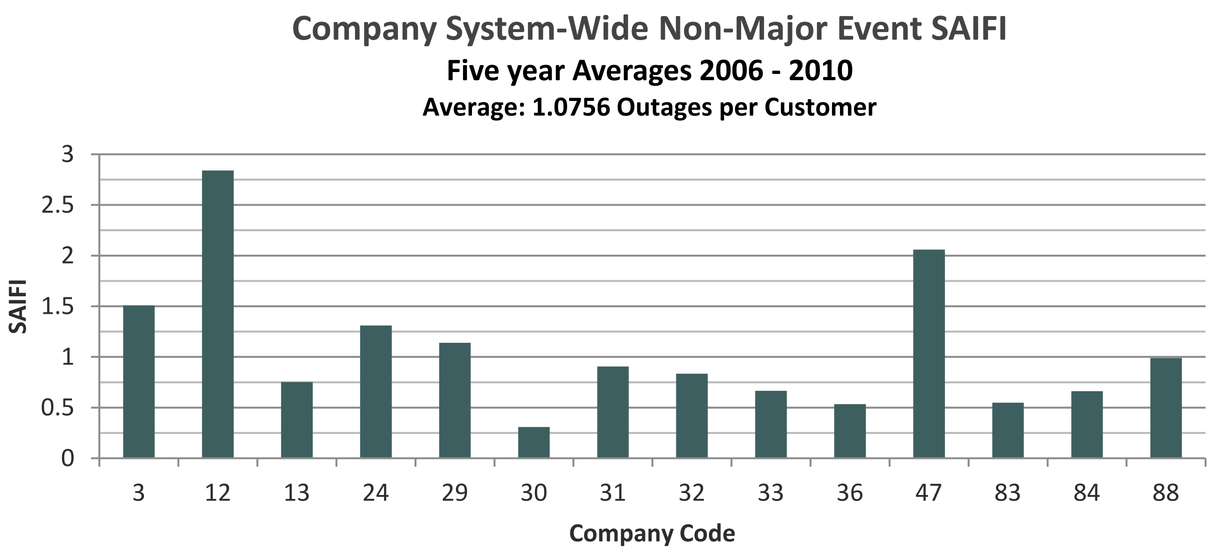


Figure 247: Company System-Wide Non-Major Event SAIFI Five Year Averages (2006 -2010)

System-Wide Major Event SAIFI

Graphs from data collected in **Question #190**

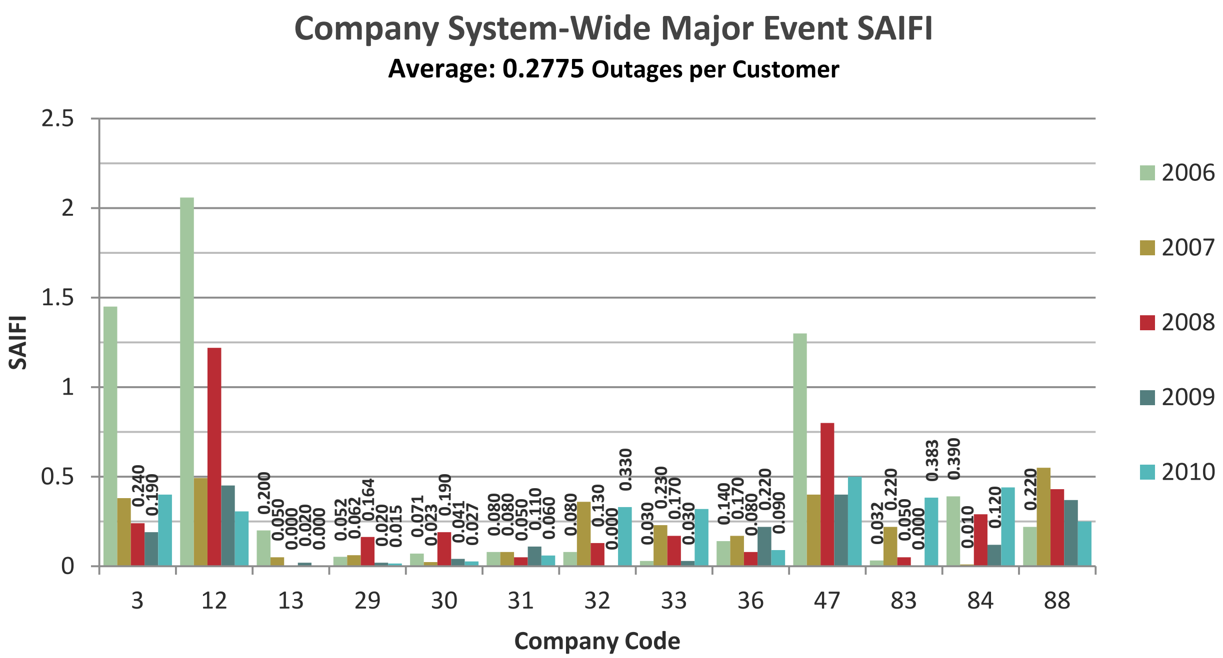


Figure 248: Company System-Wide Major Event SAIFI for Years 2006 – 2010

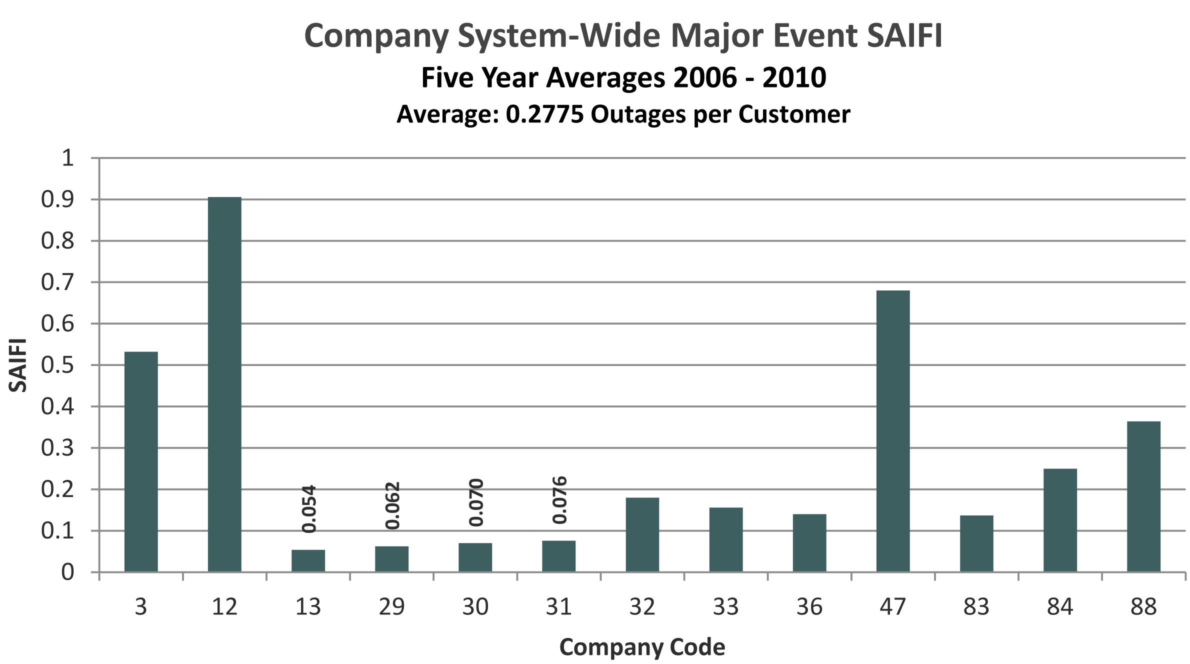


Figure 249: Company System-Wide Major Event SAIFI Five Year Averages (2006 -2010)

System-Wide Non-Major Event CAIDI

Question #191: What was your company's TOTAL DISTRIBUTION CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI) for IEEE 1366-2003 defined outages for the following years and what is the TOTAL FOR MAJOR EVENT/STORM only?

NOTE: If you do not use IEEE 1366-2003 to define major events, answer the question using your definition of storm event (supplied in question #182).

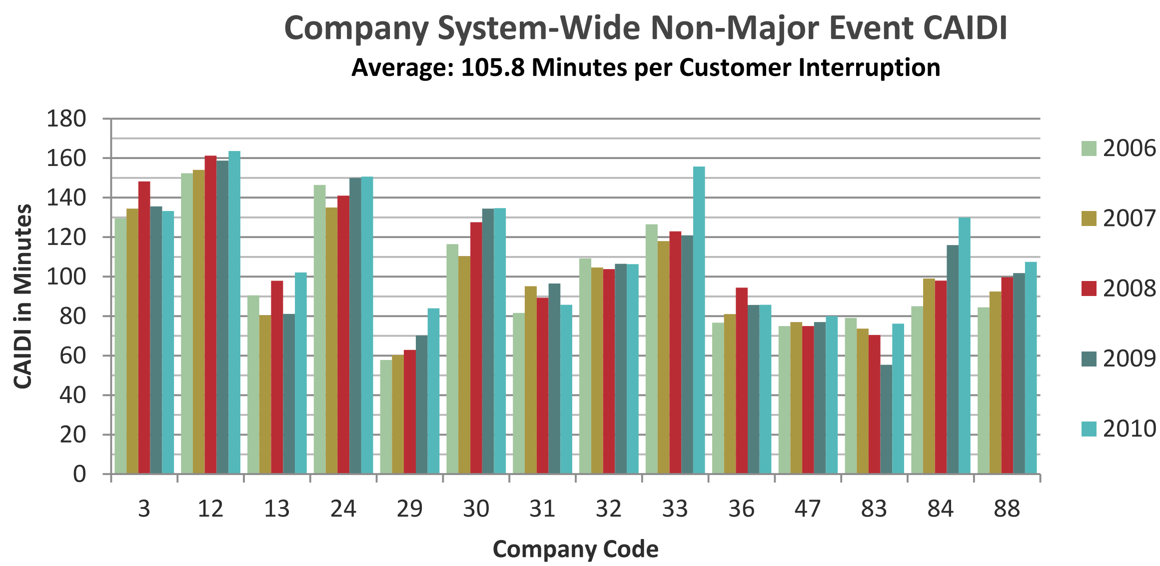


Figure 250: Company System-Wide Non-Major Event CAIDI for Years 2006 – 2010

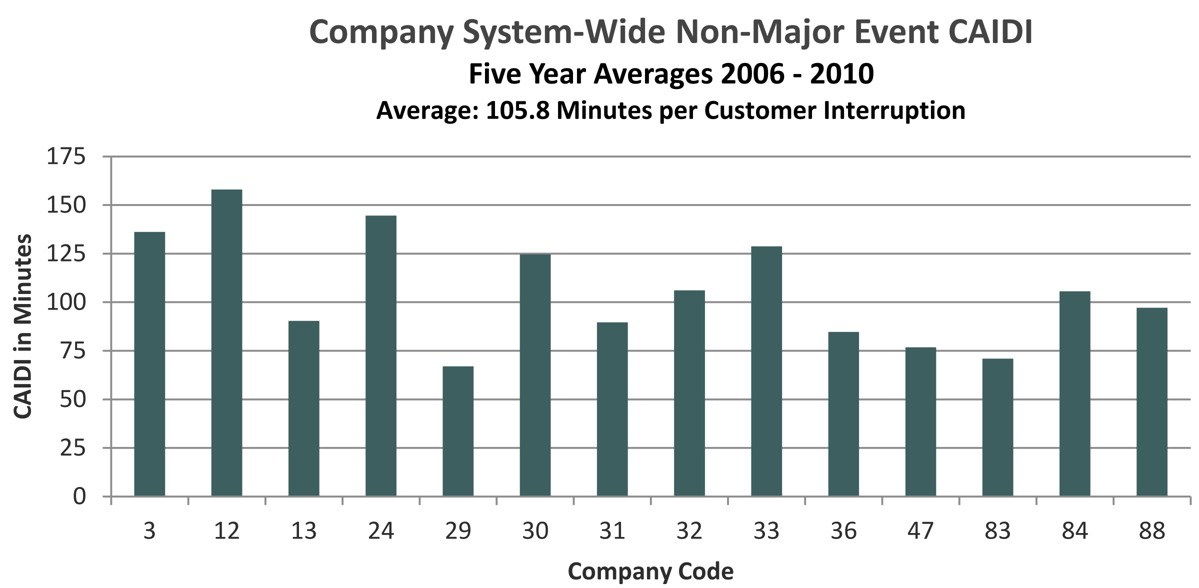


Figure 251: Company System-Wide Non-Major Event CAIDI Five Year Averages (2006 -2010)

System-Wide Major Event CAIDI

Graphs from data collected in **Question #191**

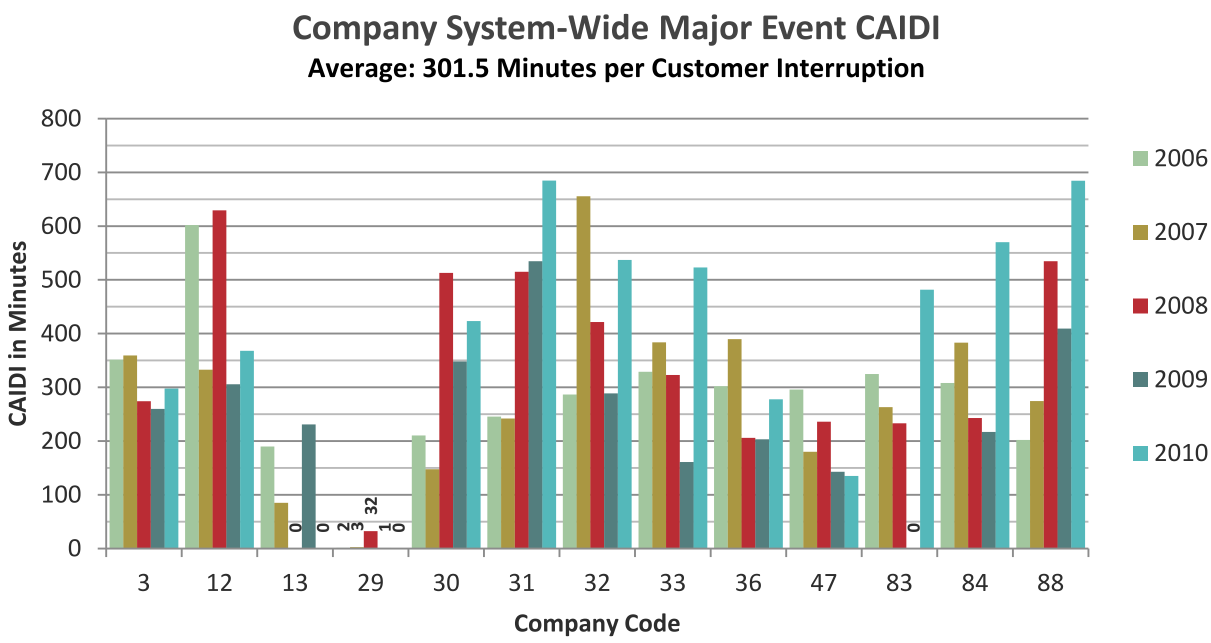


Figure 252: Company System-Wide Major Event CAIDI for Years 2006 – 2010

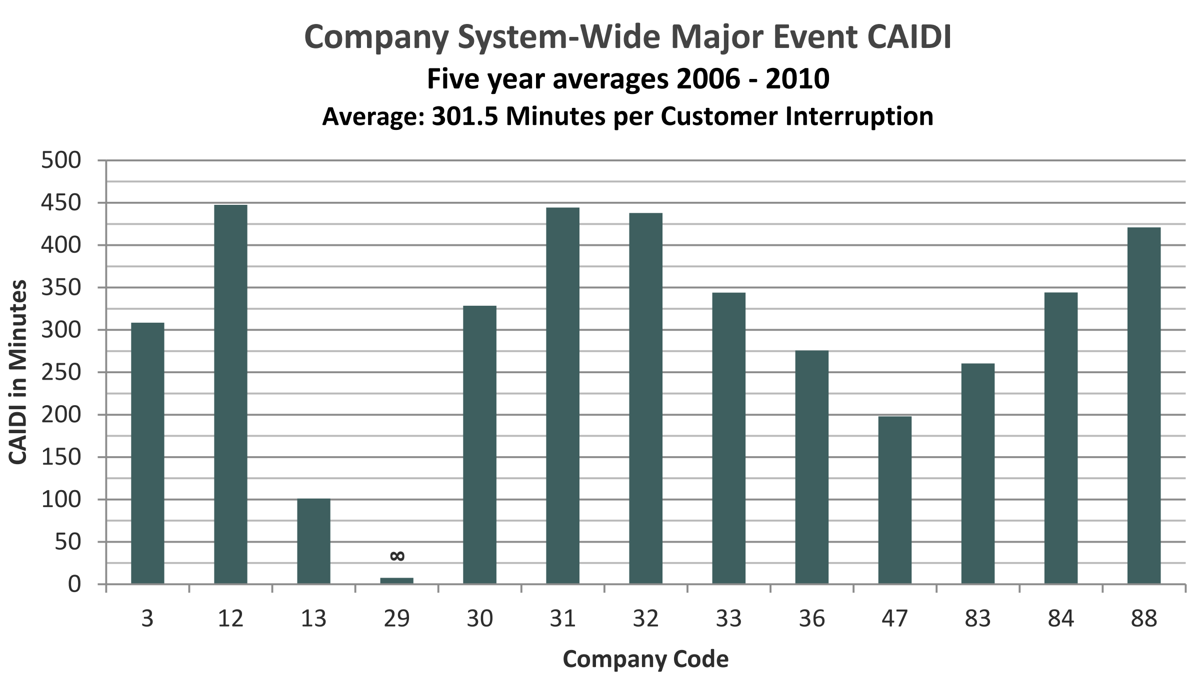


Figure 253: Company System-Wide Major Event CAIDI Five Year Averages (2006 -2010)

TREE-RELATED RELIABILITY METRICS

The graphs in this section all were generated using the data collected in question #192 (below).

Question #192: Please provide your TOTAL TREE-RELATED DISTRIBUTION SAIDI/SAIFI/CAIDI numbers for the following years AND the TOTAL SAIDI/SAIFI/CAIDI FOR TREE-RELATED MAJOR EVENT/STORM only.
NOTE: If you do not use IEEE 1366-2003 to define major events, answer the question using your definition of storm event (supplied in question #182).

Tree-Related SAIDI

Non-Major Event Tree-Related SAIDI

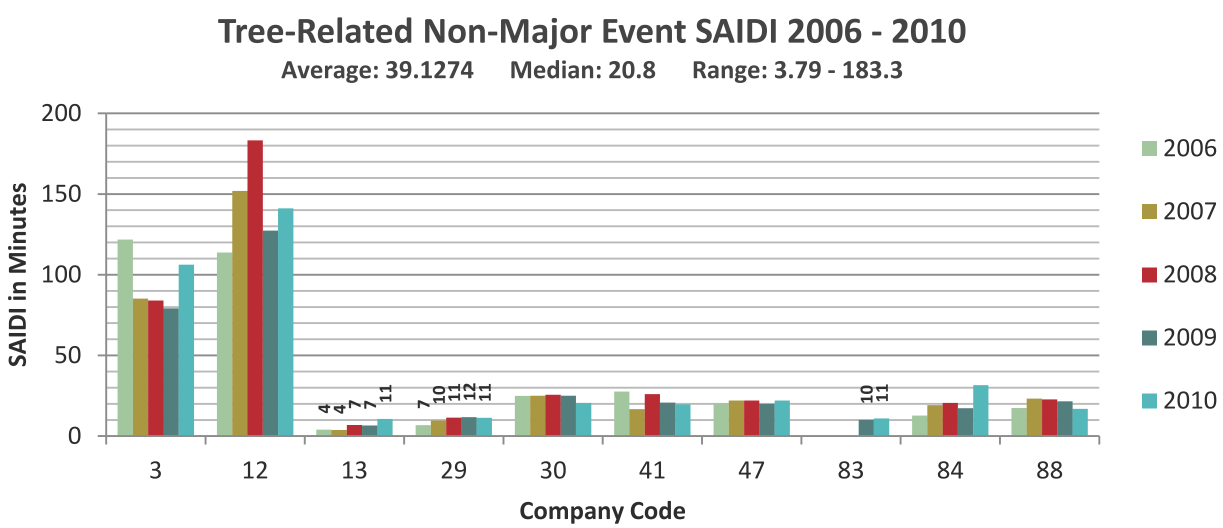


Figure 254: Tree-Related Non-Major Event SAIDI for Years 2006 - 2010

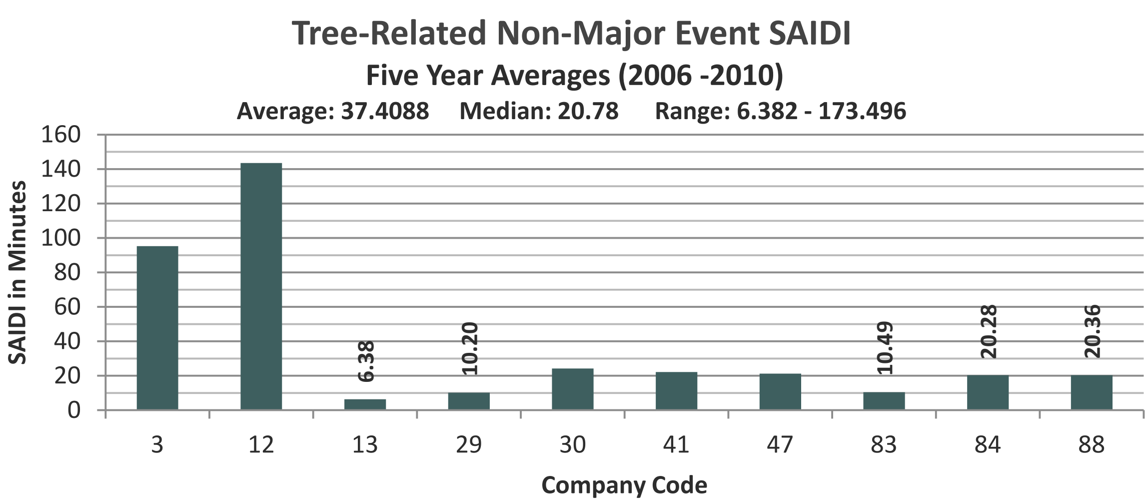


Figure 255: Tree-Related Non-Major Event SAIDI Five Year Averages (2006 -2010)

Major Event Tree-Related SAIDI

Graphs from data collected in **Question #192**

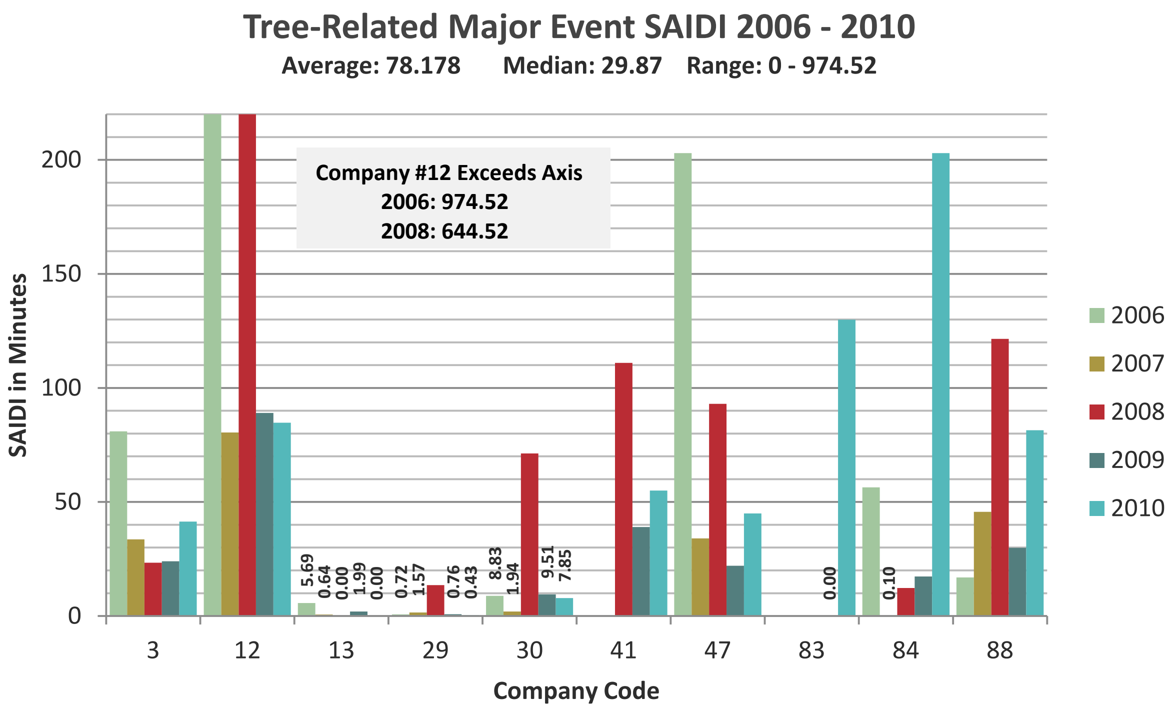


Figure 256: Tree-Related Major Event SAIDI for Years 2006 – 2010

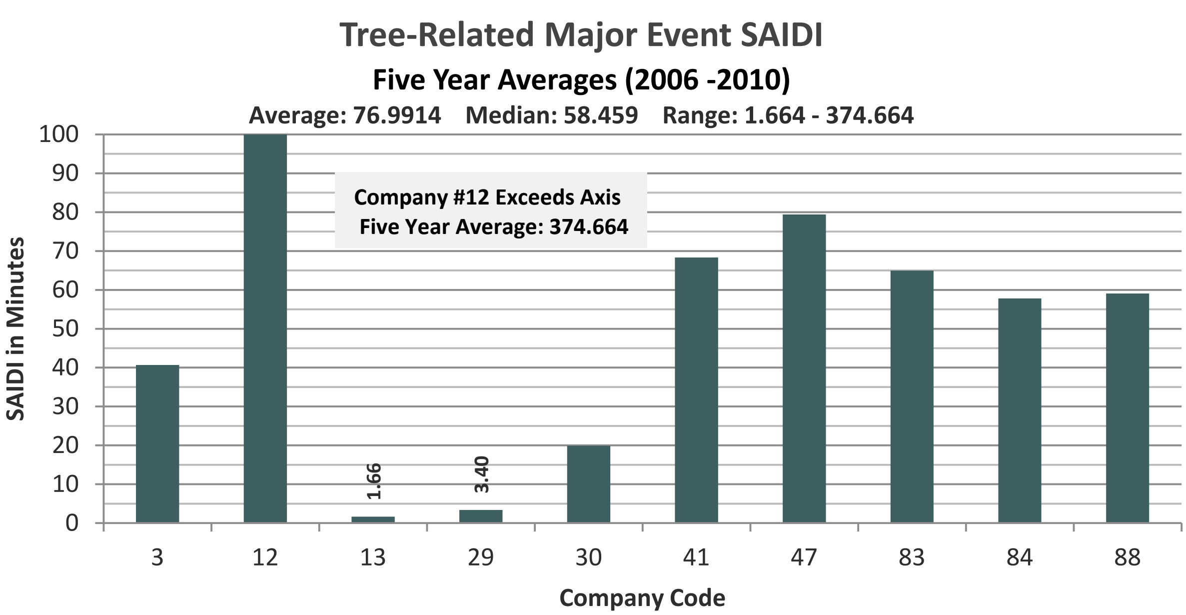


Figure 257: Tree-Related Major Event SAIDI Five Year Averages (2006 -2010)

Tree-Related SAIFI

Non-Major Event Tree-Related SAIFI

Graphs from data collected in **Question #192**

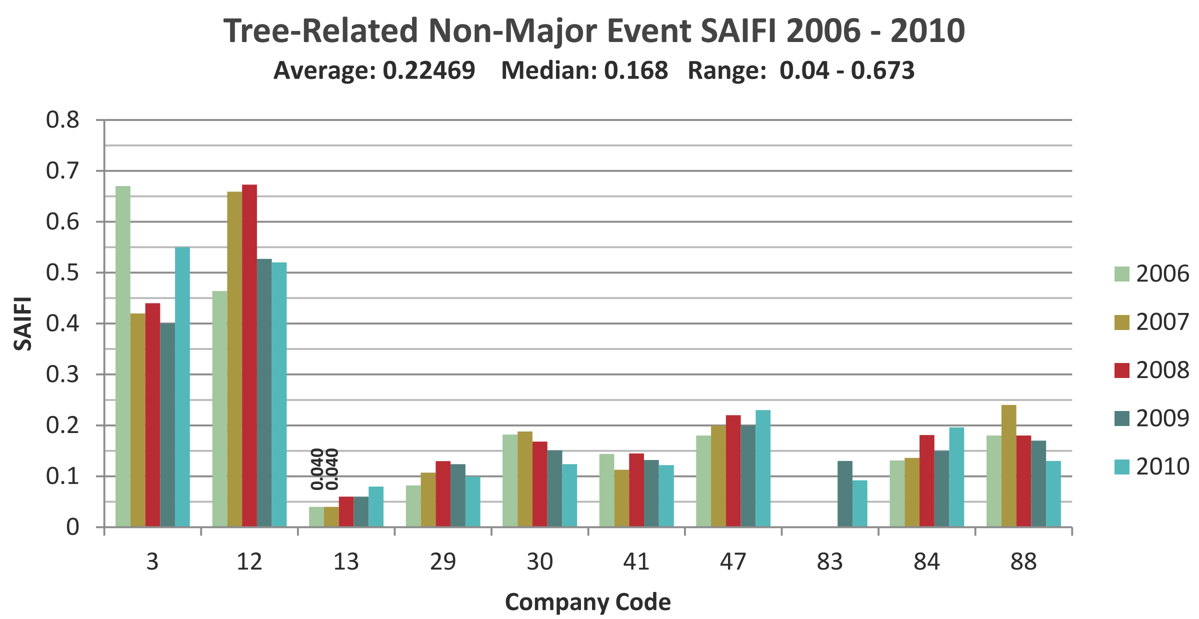


Figure 258: Tree-Related Non-Major Event SAIFI for Years 2006 - 2010

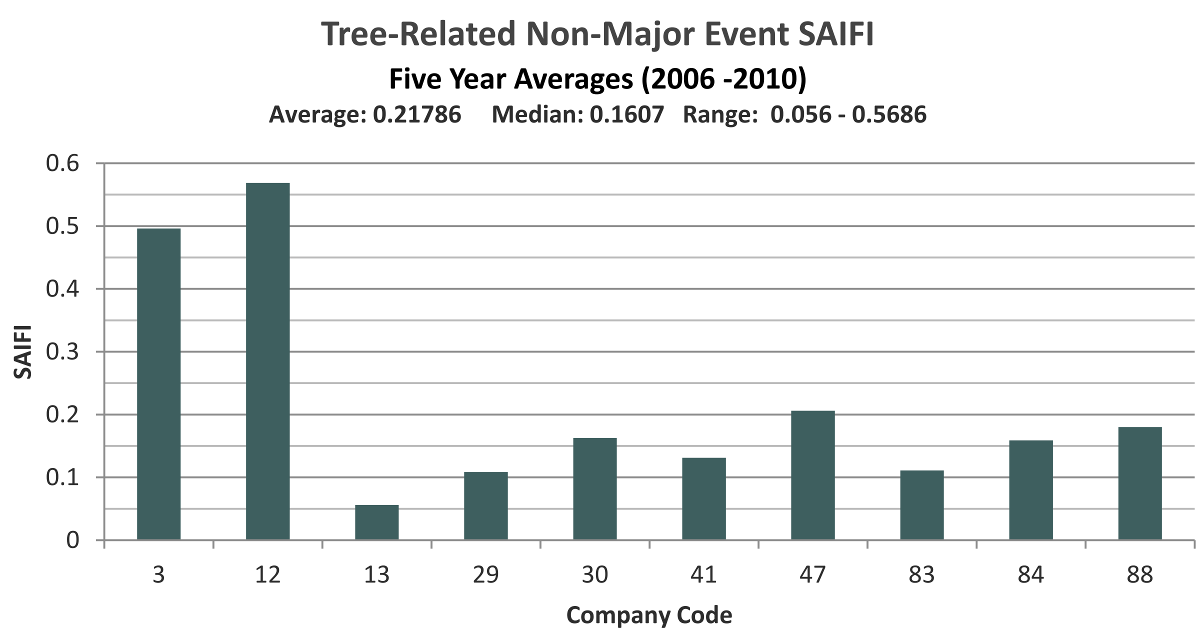


Figure 259: Tree-Related Non-Major Event SAIFI Five Year Averages (2006 -2010)

Major Event Tree-Related SAIFI

Graphs from data collected in **Question #192**

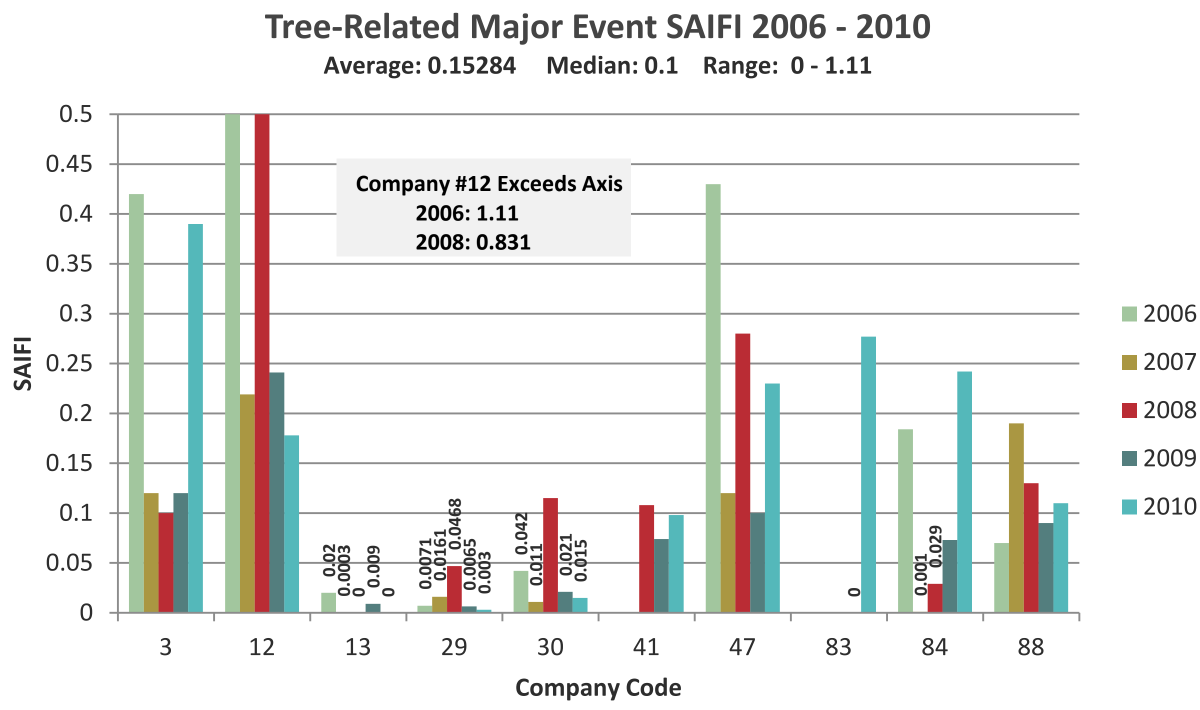


Figure 260: Tree-Related Major Event SAIFI for Years 2006 - 2010

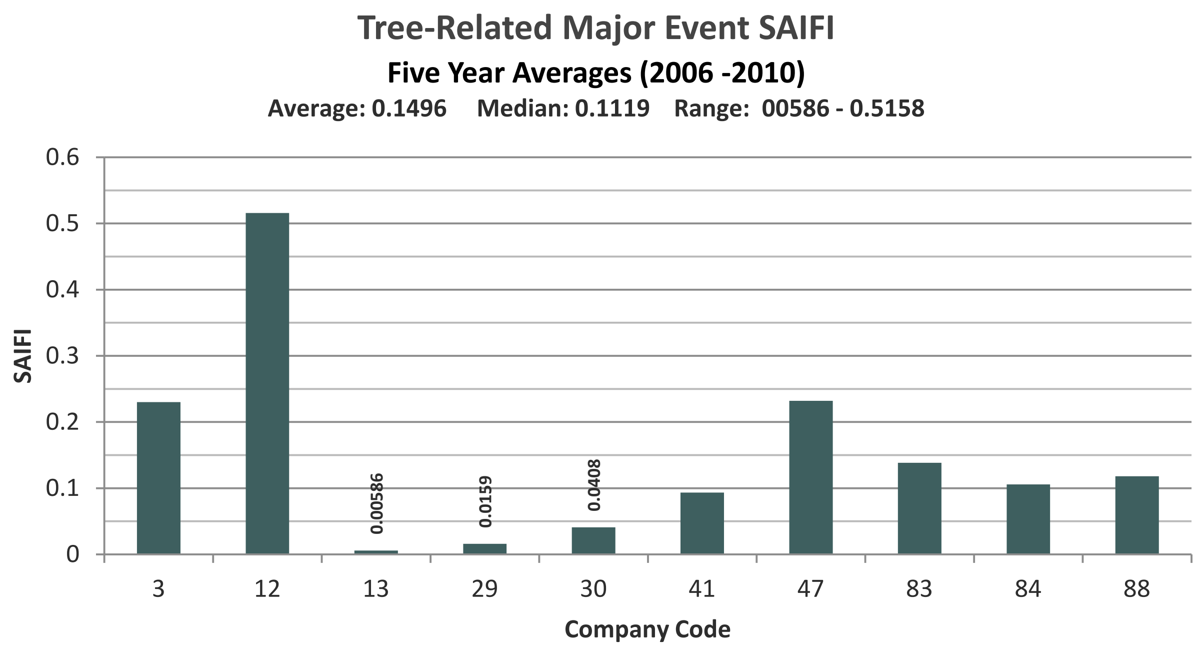


Figure 261: Tree-Related Major Event SAIFI Five Year Averages (2006 -2010)

Tree-Related CAIDI

Graphs from data collected in **Question #192**

Non-Major Event Tree-Related CAIDI

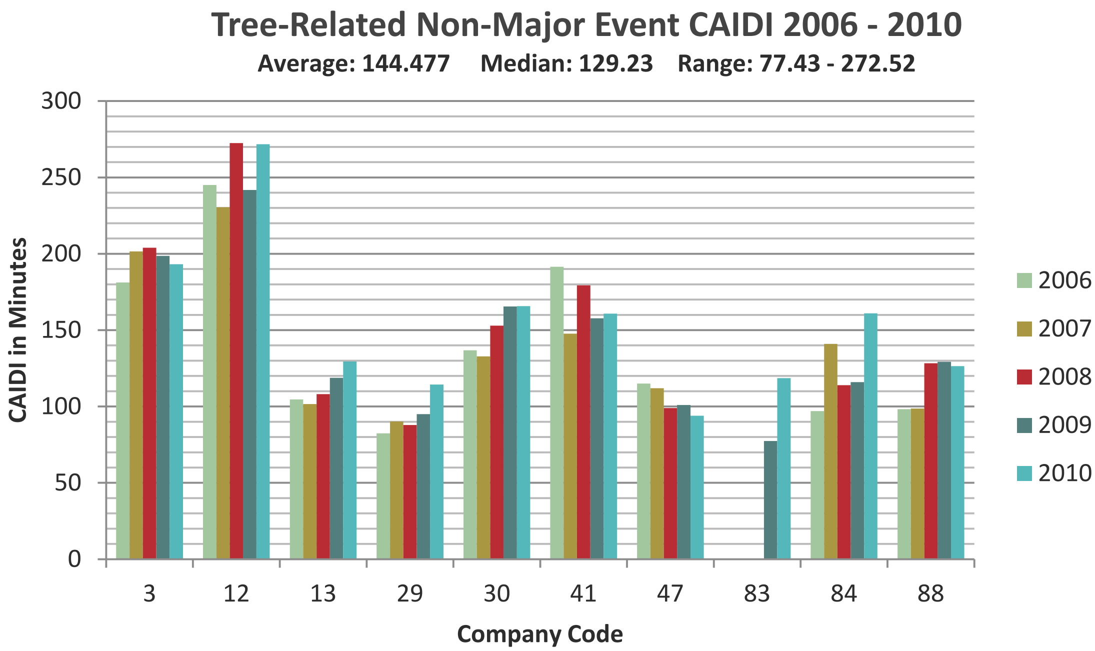


Figure 262: Tree-Related Non-Major Event CAIDI for Years 2006 - 2010

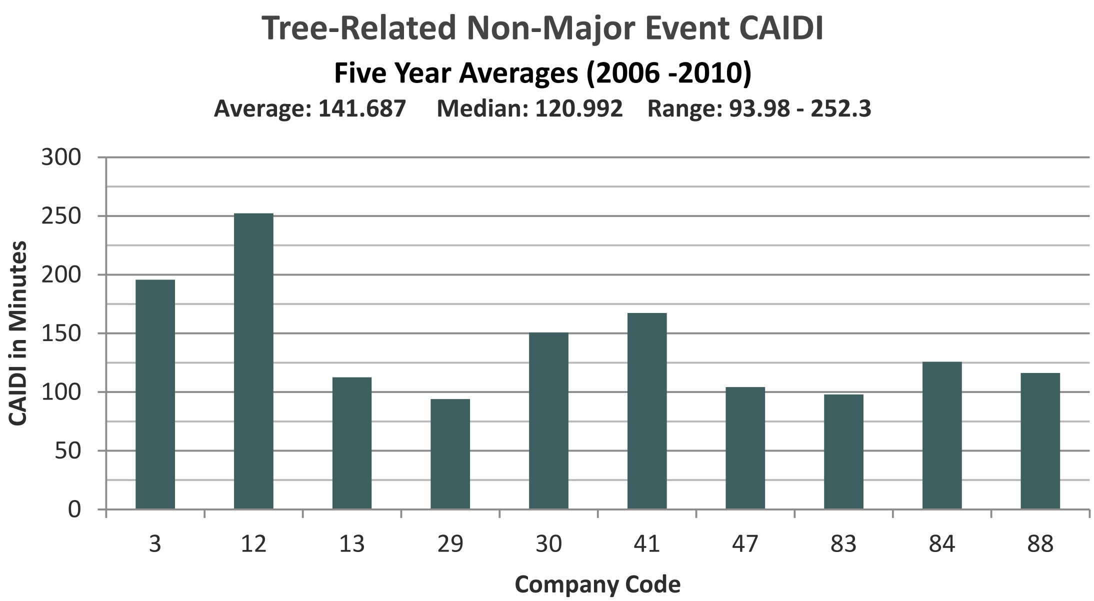


Figure 263: Tree-Related Non-Major Event CAIDI Five Year Averages (2006 -2010)

Major Event Tree-Related CAIDI

Graphs from data collected in **Question #192**

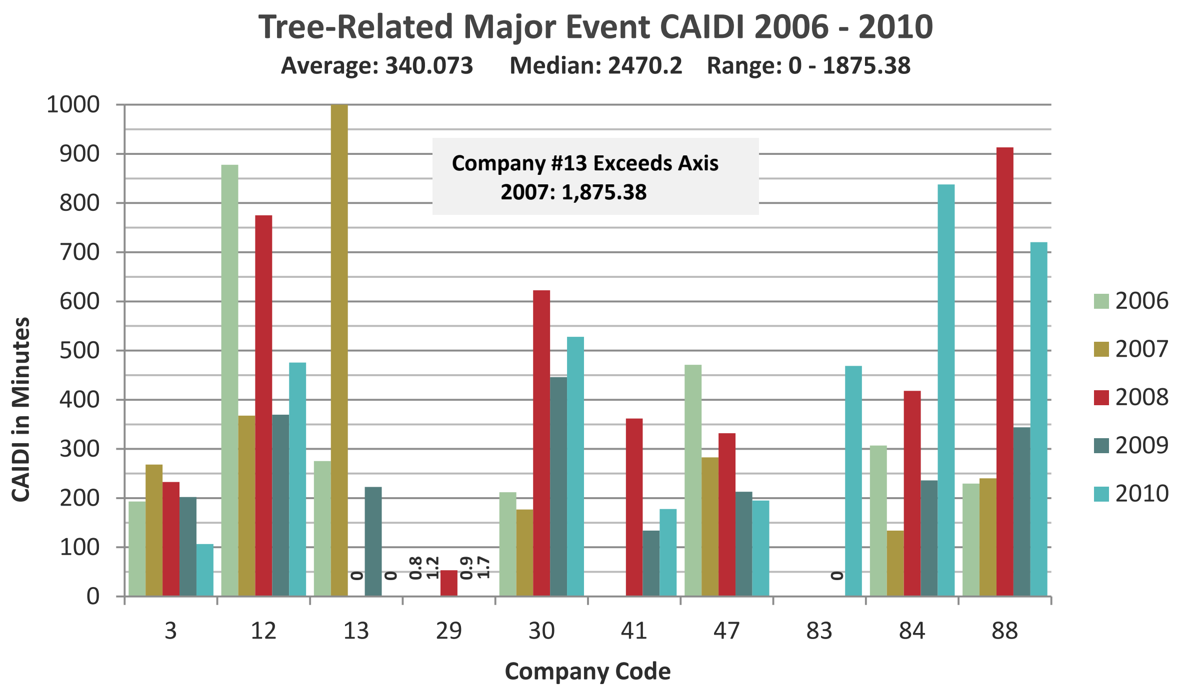


Figure 264: Tree-Related Major Event CAIDI for Years 2006 - 2010

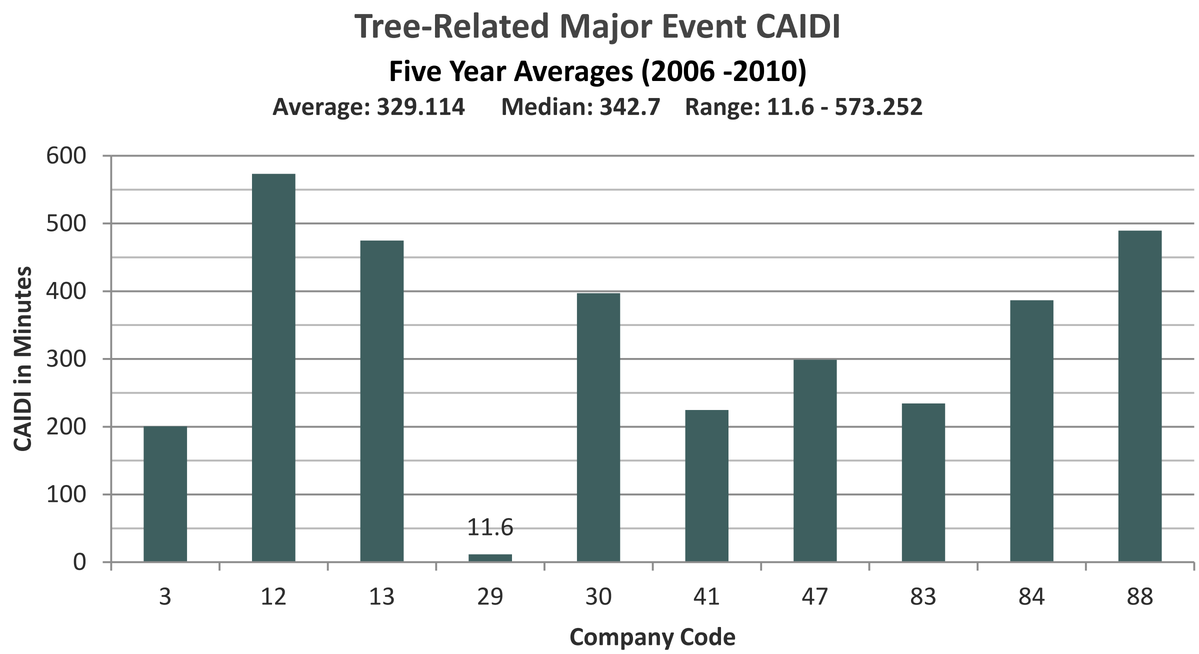


Figure 265: Tree-Related Major Event CAIDI Five Year Averages (2006 -2010)

TREE-RELATED OUTAGES DUE TO GROW-INS

Question #193: Please provide the NUMBER of SUSTAINED TREE-RELATED OUTAGES your company experienced in the following years for your DISTRIBUTION system caused by TREES GROWING INTO DISTRIBUTION LINES.

Number of Tree-Related Outages Due to Grow-Ins

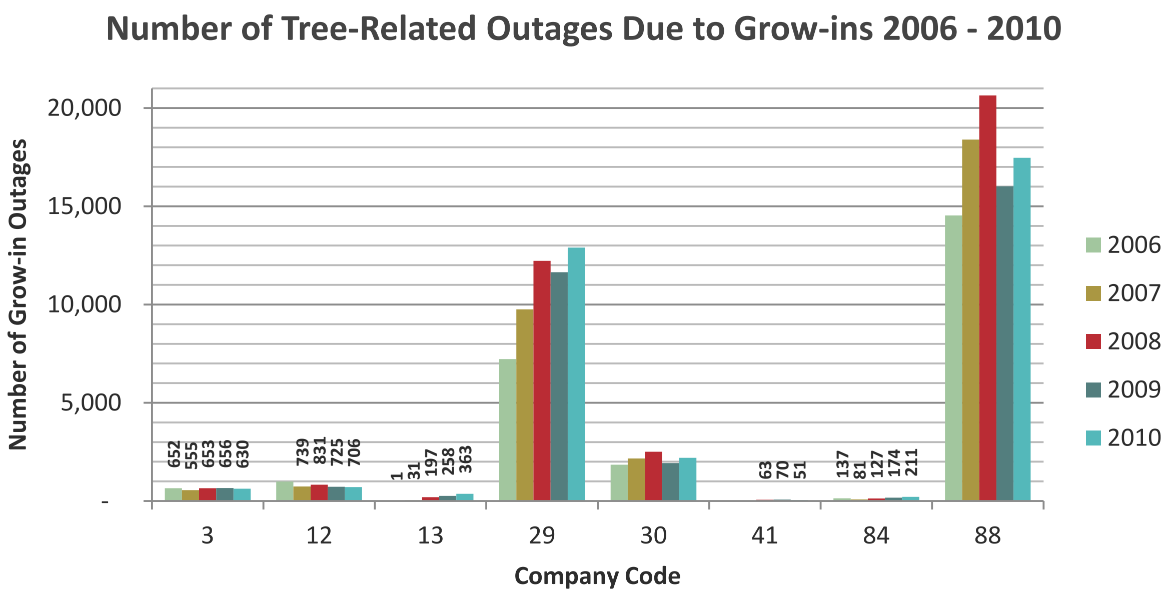


Figure 266: Number of Tree-Related Outages Due to Grow-ins 2006 - 20010

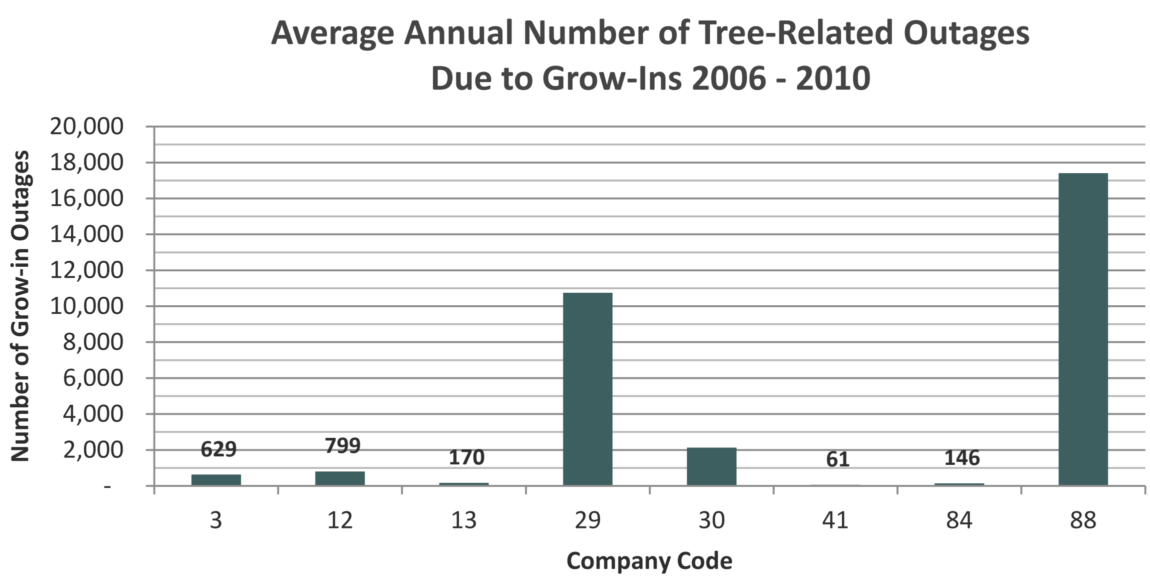


Figure 267: Average Annual Number of Tree-Related Outages Due to Grow-Ins 2006 - 2010

Percent of Tree-Related Outages Due to Grow-Ins as Calculated

Statistics calculated from data collected in **Question #193** and **Question #188**

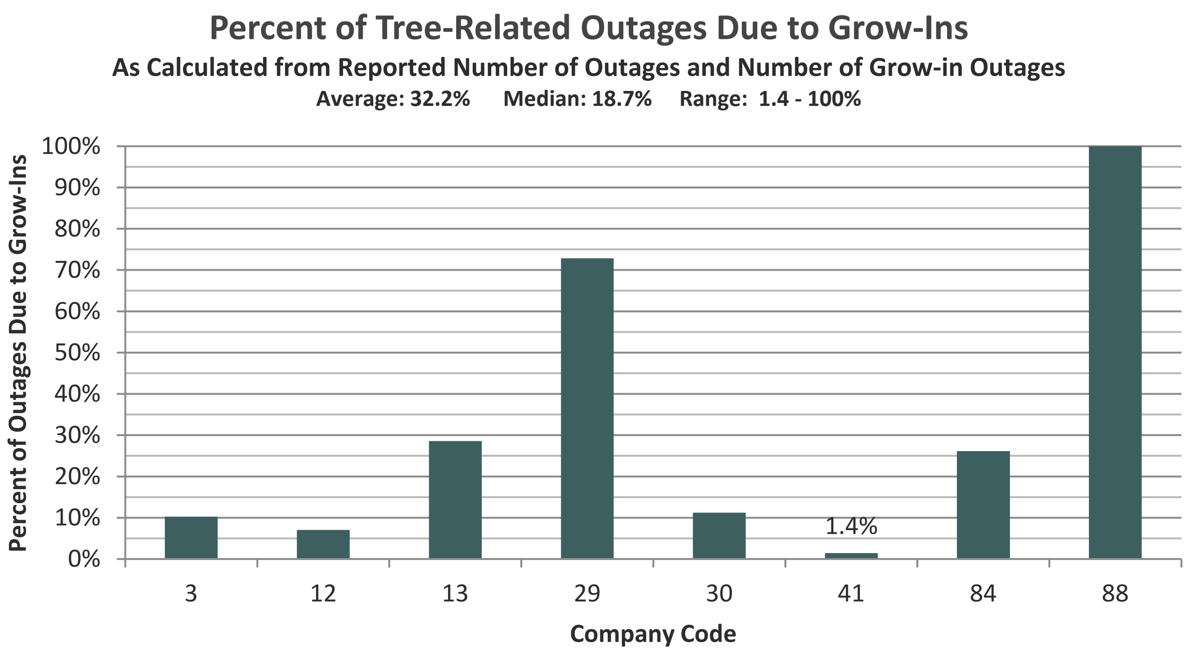


Figure 268: Percent of Tree-Related Outages Due to Grow-Ins as Calculated

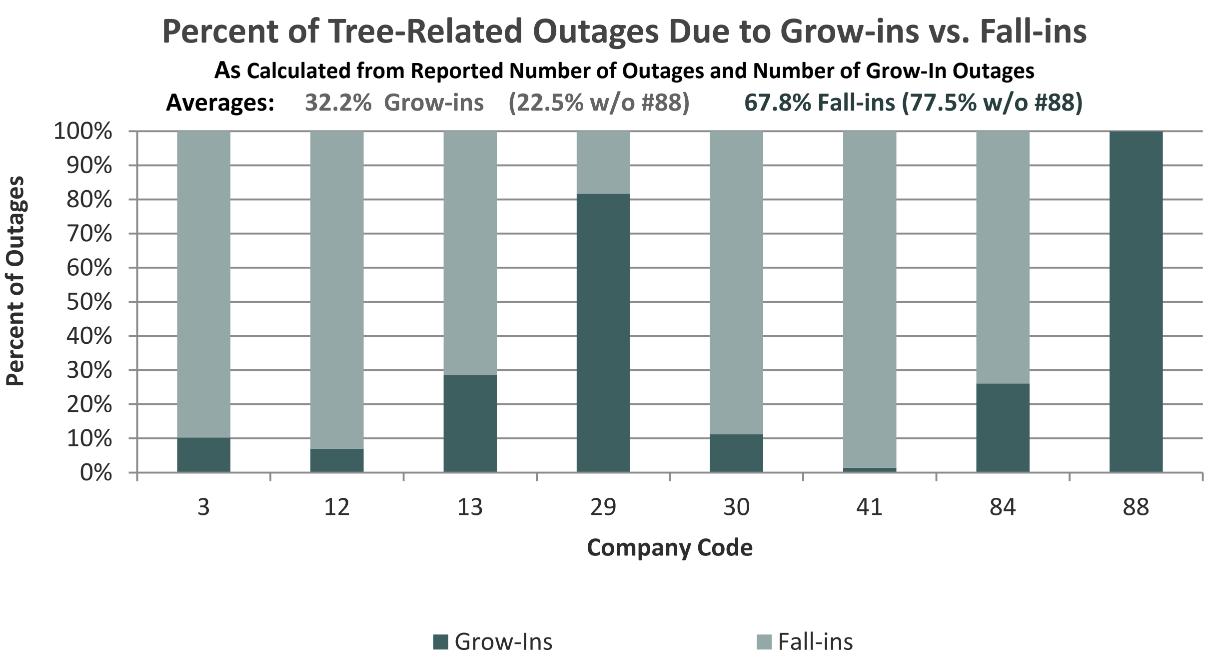


Figure 269: Percent of Tree-Related Outages Due to Grow-ins vs. Fall-ins as Calculated

Percent of Tree-Related Outages Due to Grow-Ins as Reported

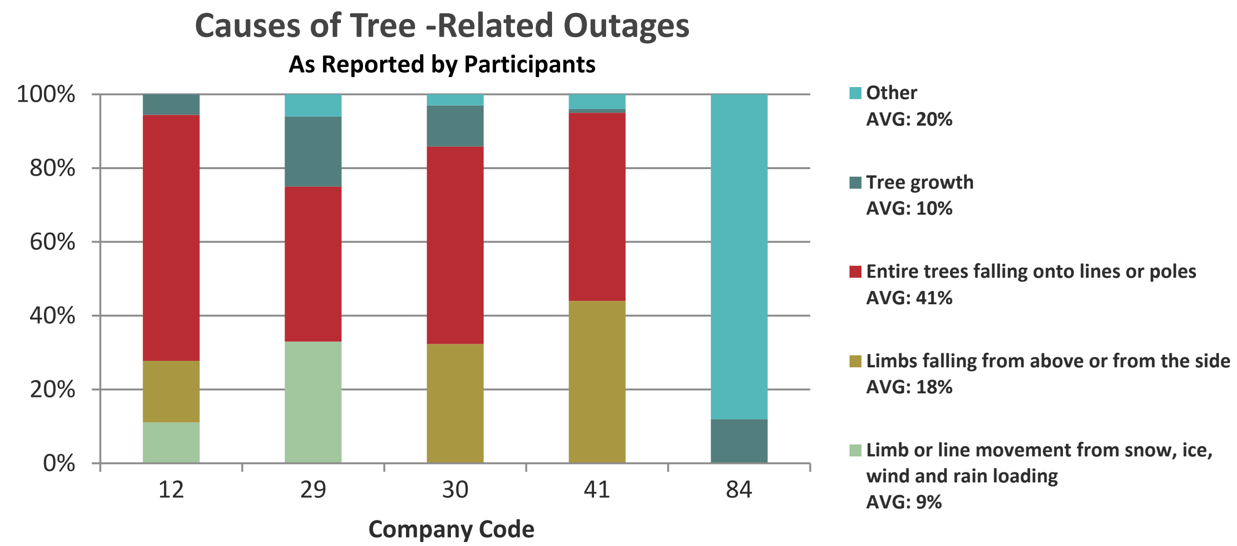


Figure 270: Causes of Tree -Related Outages As Reported by Participants

Other Causes of Tree-Related Outages
Other includes breakage or entire trees falling onto lines or poles. [Fall-In Categories Combined]
Tree Cutting Our Contractor and ground vegetation < 1% Tree Cutting 3rd party = 3%
For feeder backbone only.
Vine Outages

Figure 271: Other Causes of Tree-Related Outages

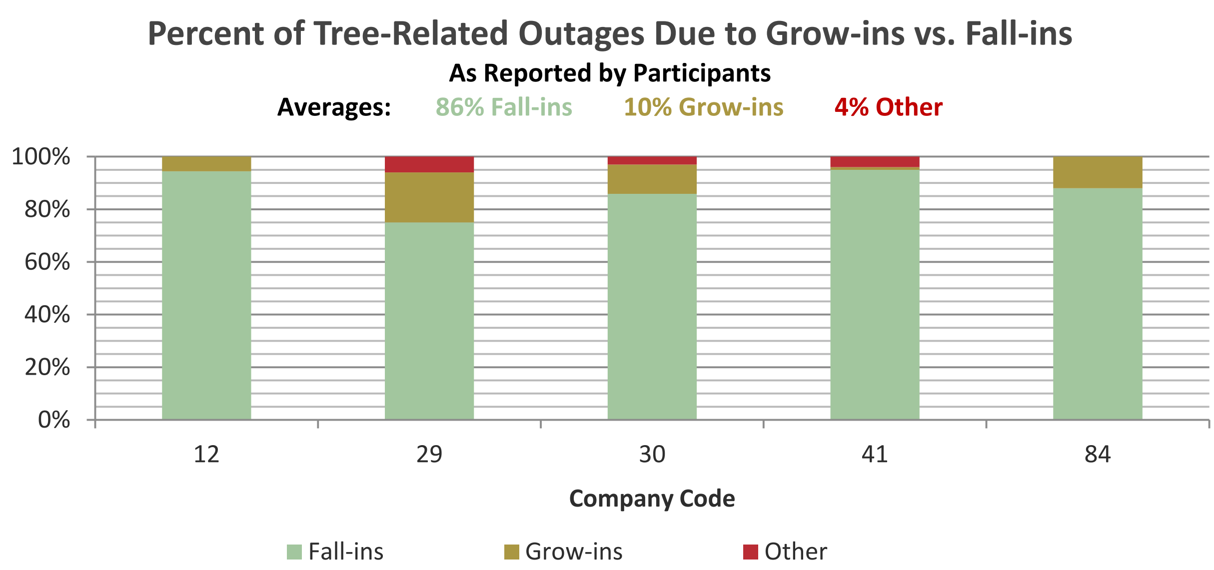


Figure 272: Percent of Tree-Related Outages Due to Grow-ins vs. Fall-ins as Reported by Participants

Data Discussion on the Causes of Tree-Related Outages

The following conclusions can be inferred from the comparison of graphs related to *Causes of Tree-Related Outages:*

1. Three of the companies that reported reasons for outages in percents show a high correlation with the calculated statistics (See Figures 268 and 271). This implies that these companies have submitted reliability data to the survey that is consistent with the data they used to calculate reliability statistics. This is important because it verifies there are no data entry errors or inconsistencies in their reliability metrics.
2. A majority of the participants do *not* track the causes for tree-related outages routinely within the UVM program. If they are tracked, this statistic is not readily available to the UVM department. This can be inferred from the low response rate of companies reporting the percent of tree-related outage causality.
3. Since reliability is one of the main objectives of a UVM program, the tracking of the *causes* for tree-related outages should be a high priority.
4. A UVM program would derive benefits from having a database that tracks causes of tree-related outages. Without knowing the cause of tree-related outages, it is hard to improve reliability.
5. A UVM program would also derive benefits from routinely investigating how the cause of an outage is determined. The following are some examples of challenges for understanding UVM efficacy and tree-related outages in the context of reliability measurements:
    a. Multiple tree events may contribute to a single outage if a feeder is out and taps are also damaged. In this case, the extent to which this affects SAIFI or number of tree-related outages may not be recognized.
    b. A tree growing into and arcing to a conductor or falling onto a conductor but not interrupting power may not be interpreted as a reliability issue because no outage was caused.
    c. Reliability metrics are an on-off measurement that may be overshadowing other potential measurements of the resiliency of the system. Non-major event days may not be a good indicator of the reliability of the system in terms of predicting what will likely happen if there is a major event. This may be an area where reliability metrics are disguising the effectiveness of a UVM program.

UVM DATA MANAGEMENT

Data Systems Employed for UVM

Question #216: Please briefly describe the electronic system or systems that you employ for workplanning, inspections, dispatching and documenting UVM work activities and verifying work has been performed according to specification.

Data Systems Employed for Utility Vegetation Management
Excel and Access programs in-house.
An in-house SQL based database housing customer requests and contractor work history.
Work is assigned to contractor. When completed, we will perform 100% field audit on all planned work.
Planning - by circuit a database tracks inspection and trimming start and completion dates Inspections - contract inspectors carry hand-held devices that link to maps and our company's GIS mapping system. The system records customer, tree, location and alert information. It also includes reference & procedural documents. Customer Notification - Besides face-to-face customer contract by our inspectors, an automated system is used to call customers before tree work starts (can also be used prior to inspection patrols)
Crew audits, random samples, Powell work tablet, in-house database, spreadsheets, Microsoft project, access, sequel server, SAP Cognos.
We use an in-house GIS based work management system called VegSMART
- ArcGIS/Clearion application used to plan work, currently used for palm management and expanding to other work types. - Work Management System (WMS) Houses maintenance and corrective work tickets, tracks schedule, progress and completion - SAP Payment System - VMTVS (Timesheet Validation System) Upload and validate T&M data from vendor - TCMS (Trouble Call Management System) Manage restoration tickets and in-service trouble work
SAP - Work order generation and management. We are in the process of migrating data and processes into this system GIS - Spatial integration with GIS for asset mapping, data collection and program planning. Forestry Management System (FMS) - A custom built web based work reporting system which interfaces with our customer data. Used to plan, manage and execute the vegetation management program. This includes a mobile component.
Weekly inspections of completed work, done by hand and recorded/stored by Word program. Nothing special. Hours recorded and tracked in SAP
Clearion - GIS-based software solution that operates within ESRI ArcGIS framework. This software has been established for vegetation management mapping and service process. It is used to map the vegetation GIS layer and provide information regarding work performed in the field. It is fully integrated with company's work management system and customer service system.
We use the TRES software for data collection and everything else is done manually
Access programs that hold historical information and schedules on a five year rotating basis.

Figure 273: Data Systems Employed for Utility Vegetation Management

Data Systems Employed for Utility Vegetation Management (Continued)
Up to December 2011, MS Access (inspection, billing control, work assessment) many data base, not consolidated MS Excel (planning, dash board), SAP R/3 (customer inquiries, new work, billing process) Smallworld (mapping) Beginning January 2012, CLEARION/ESRI (inspection, billing control, work assessment, planning, dash board, mapping) one and only data base consolidated. SAP R/3 via CLEARION/ESRI interface (Customer inquiries, new work, billing process).
Vegetation Outage data is achieved on a Company software program. We can go back many years to find any vegetation outage data. All other items such as workplanning, inspections, and all other pertinent UVM data is stored on a secure server and only employees with permission have access to view or work in the files.

Figure 274: Data Systems Employed for Utility Vegetation Management (Continued)

Types of Data Management Systems Used for UVM

Objective: The objective of this question is to discover what data management systems are being used.

Question #217: What data systems do you use for different aspects of your Vegetation Management System?

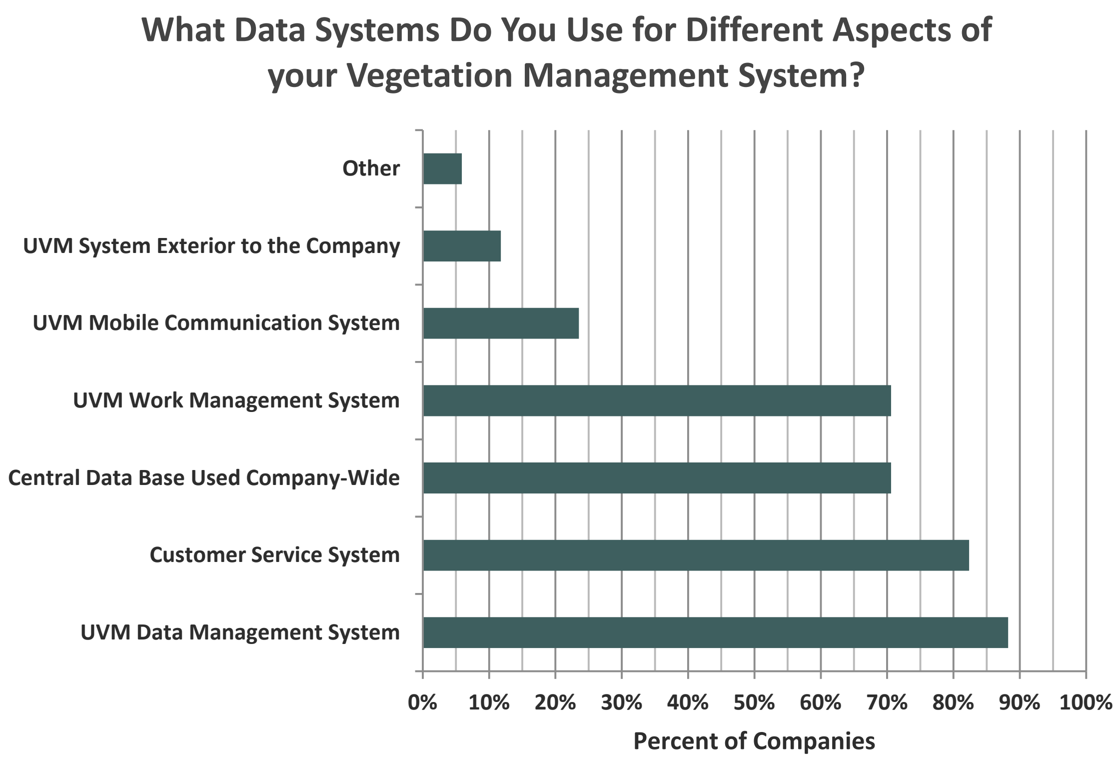


Figure 275: Aspects of UVM Supported by Electronic Data Systems

More data from this question will be available next report.

Data Collection Formats

Objective: The objective of this question is to determine how vegetation management data is collected, stored, transmitted and used.

Question #218: The following is a list of typical activities in a utility vegetation management program. Check all the formats in which each of these activities can be found. Check all that applies for each activity.

Note: Sample set was 17 participants.

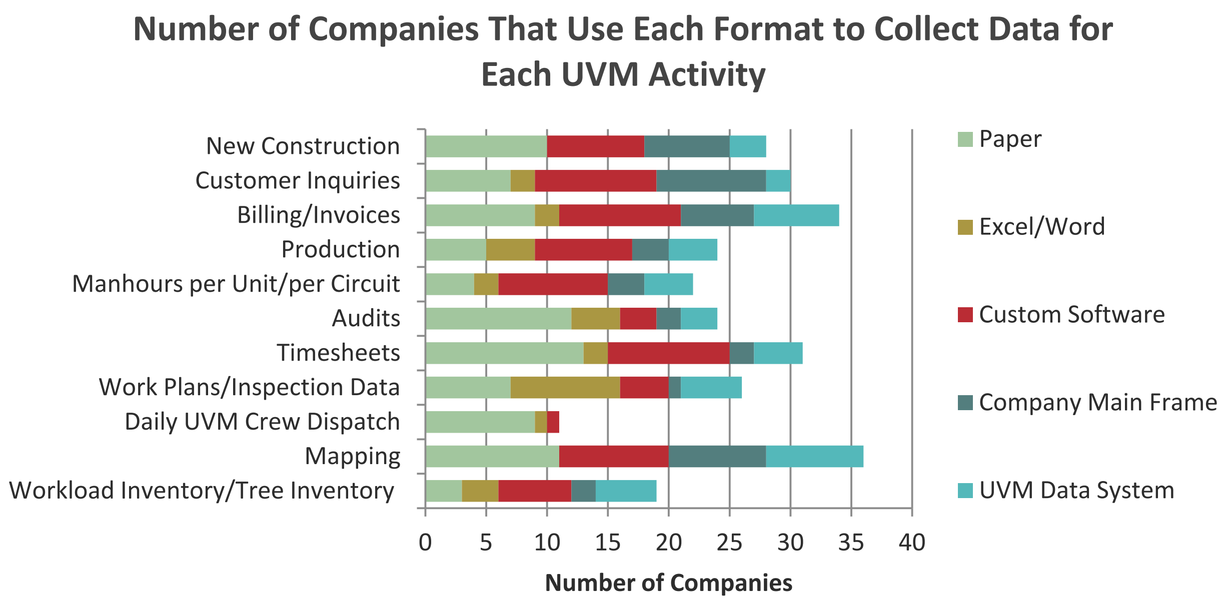


Figure 276: Number of Companies That Use Each Format to Collect Data for Each UVM Activity

Comments on Data Collection Formats
All of the paper collection is later stored electronically.
Take note that both system before and after January 2012 are considered in the answer.

Figure 277: Comments on Data Collection Formats

Discussion on Data Collection Formats:

This question had a dense amount of data associated with it. Further investigation into some of the details given in the responses will provide insight into data collection formats in UVM departments and how the UVM department interfaces with other departments in the company.

A cursory analysis of the data indicates the following:

1. Paper is still the predominate method of recording, storing and transmitting data to and from the field, as well as internally.
2. Many companies use more than one format for data collection and storing, thus, most likely, indicating some duplication of efforts. Of note is the comment on the table above, "All of the paper collection is later stored electronically." Although this participant was the only one that mentioned this issue, a thorough look at the data indicates that many companies have two or three data collection and storage formats used for the same task.
3. There is a significant increase in the use of customized software for many of the UVM tasks since the 2009 Benchmark Survey. Only **47%** of the companies in the **2009** CNUC Benchmark Survey utilized customized software somewhere in the UVM department as opposed to **88%** of the companies in **2011**.

WORK PLANNING AND UTILITY VEGETATION MANAGEMENT

Influence of Work Planning on UVM

Objective: Determine the extent to which line clearance work is influenced by field inspection and planning.

Question #219: Please rate the following work-planning activities according to the how much they were used to plan line clearance work over the last five years.

Since specific descriptors were used in place of rankings in this question, the following type of data representation (Figure 278, next page) was found to be the most appropriate.

NOTE: All work types listed below on graph (Fig. 278) had 16 companies supply the percent of time that field inspection and planning was used, EXCEPT the top category had 17 companies.

It is interesting to note that 59% of companies responding are utilizing field inspection planning for the majority of their work.

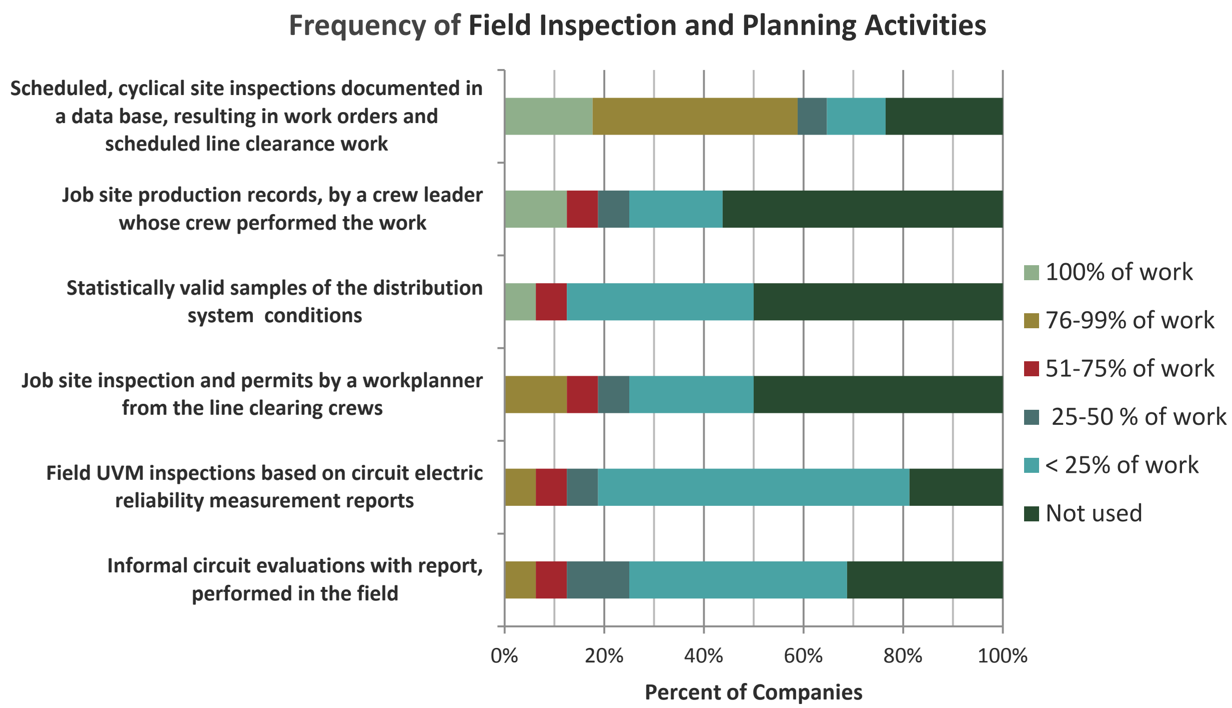


Figure 278: Frequency and Type of UVM Work Where Field Inspection and Planning Is Utilized

Comments on Influence of Field Inspections and Planning on UVM
By cycle
Field UVM inspections based on circuit electric reliability measurement reports for tree removal planning only. [Other Work Type]
Estimates

Figure 279: Comments on Influence of Field Inspections and Planning on UVM

Descriptions of UVM Work-Planning Programs

Question #220: If you have a work-planning program, please choose the option that best describes your program.

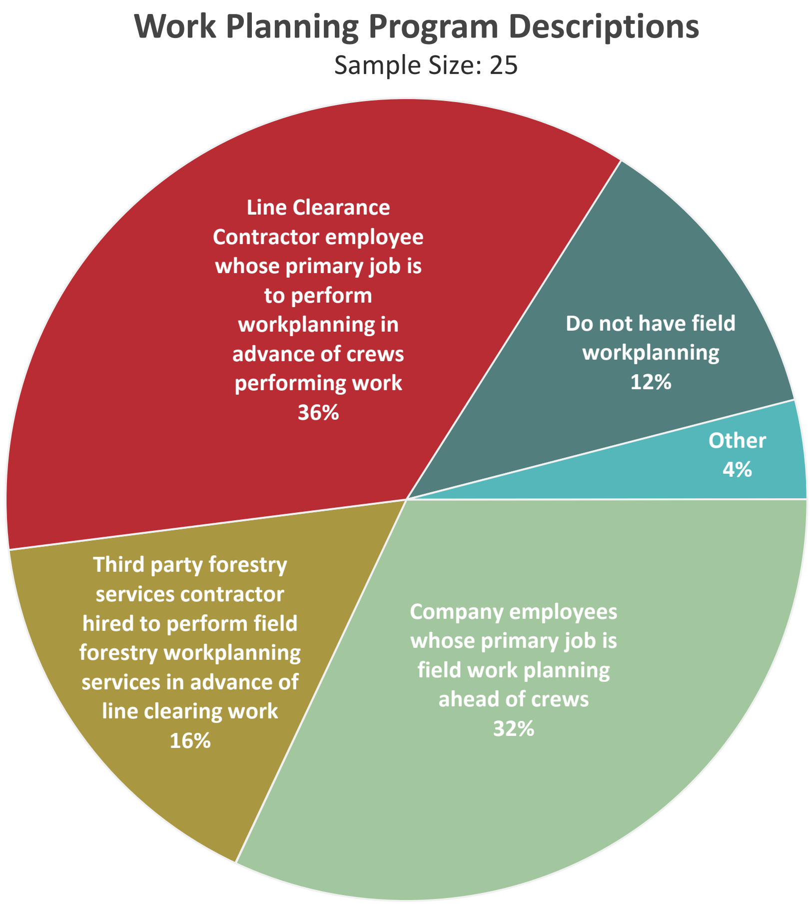


Figure 280: Work Planning Program Descriptions

Other UVM Work-Planning Program Descriptions
Tree removal and brush clearing: Company employees whose primary job is field work planning ahead of crews. Pruning: both contractor and company are doing their own workload assessment and get a financial agreement before work. After that work is done based on clearance rules.

Figure 281: Other UVM Work-Planning Program Descriptions

Work Planning Scheduled in Advance of Line Clearing

Question #221: If you employ work planning services, how much in advance of the line clearance crews is the work planned, on average?

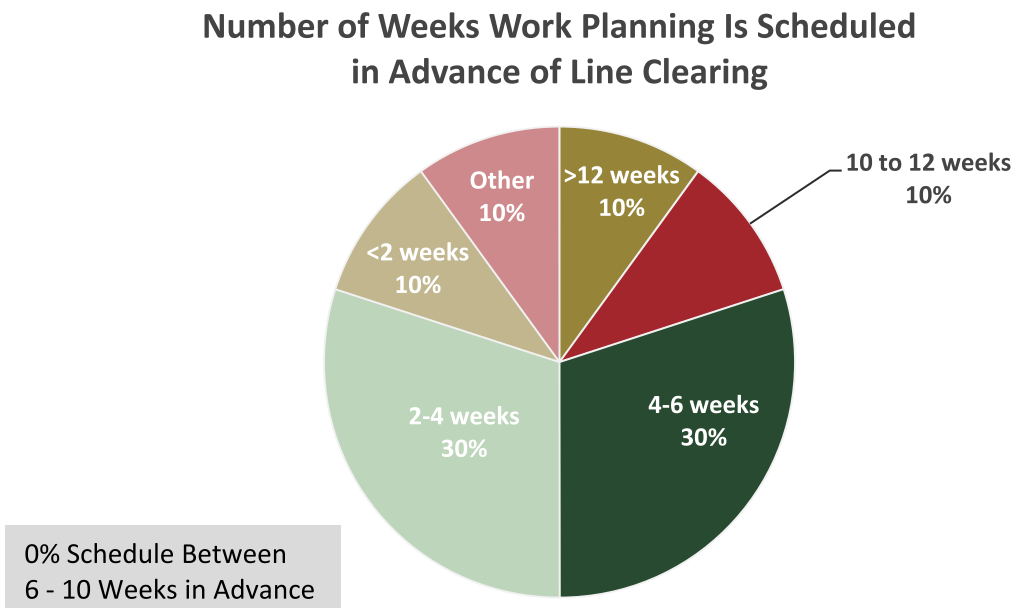


Figure 282: Number of Weeks Work Planning Is Scheduled in Advance of Line Clearing

Comments on Work Planning Scheduled in Advance of Line Clearing
For pruning: inventories must be completed at the latest 1 month before the execution of the works, and as soon as possible after the end of the season of growth preceding the works. For removals and brush clearing more than 12 weeks
The general foreman/job planner obtains all permission for their crews, 2- weeks in advance

Figure 283: Comments on Work Planning Scheduled in Advance of Line Clearing

Titles and Positions of Work-Planning Personnel

Question #222: If your UVM program has a field work-planning component, which of the following positions do you employ? Check all that apply.

Note: Graph follows comments.

Comments on Titles Positions of Work-Planning Personnel
This is one position who does it all depending on the area worked.
We employ forestry technicians which complete the entire work planning/notification programs.
The general foreman/ job planner for each UVM contractor that works for us does the notifying

Figure 284: Comments on Titles of Work-Planning Personnel

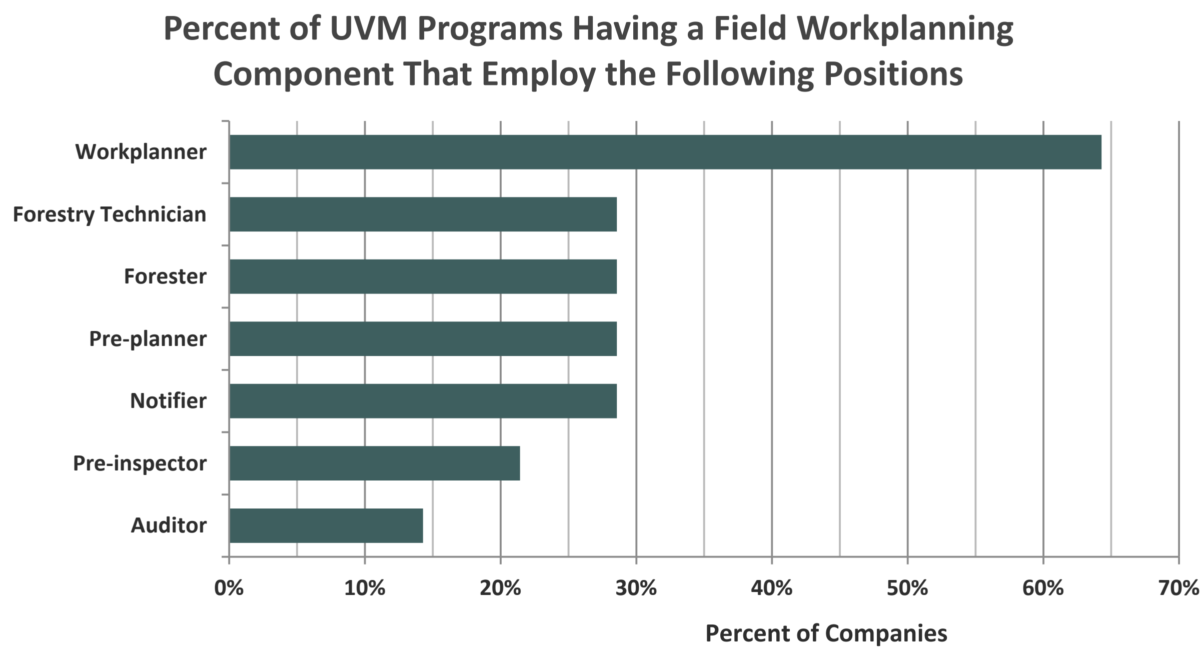


Figure 285: Percent of UVM Programs Having a Field Workplanning Component That Employ the Following Positions

Work-Planning and the UVM Interface between the Utility and the Customer

Objective: To understand the UVM planning interface between the Utility and the Customer.

Question #223: If you have foresters, preplanners, workplanners, notifiers or auditors included in your distribution UVM program, please chose from the following list the types of customer communications that these individuals perform as parts of their routine work.

Note: Graph follows comments.

Comments on UVM Interface between the Utility and the Customer
Notifiers are same person as work planners.
Other refers to external UVM Contractors.
General Foreman or Foreman
Our Forestry Technicians complete this role.
Other equals contractor General Foreman or Foreman.
Other= General foreman for contractor
Others who are helping us in communication are members of our public communication teams.

Figure 286: Comments on UVM Interface between the Utility and the Customer

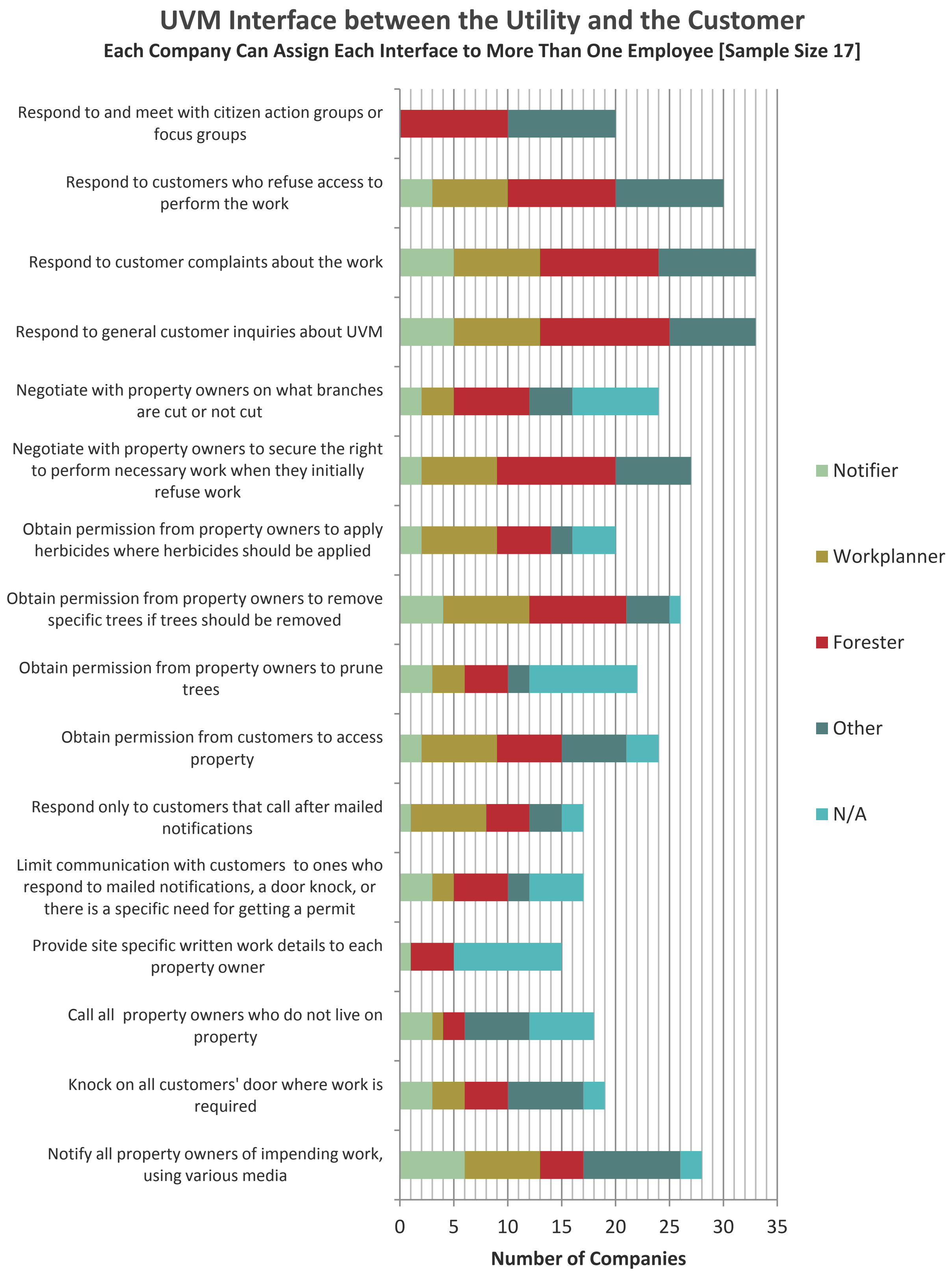


Figure 287: UVM Interface between the Utility and the Customer

Planning Work for Line Clearance Crews

Objective: To discover how work is planned in the field and the duties of various positions assigned to perform field planning work.

Question #224: Which of the following activities are performed routinely by notifiers, preplanners, forester, etc., who provide field workplanning for the company and for the crews who perform the work.

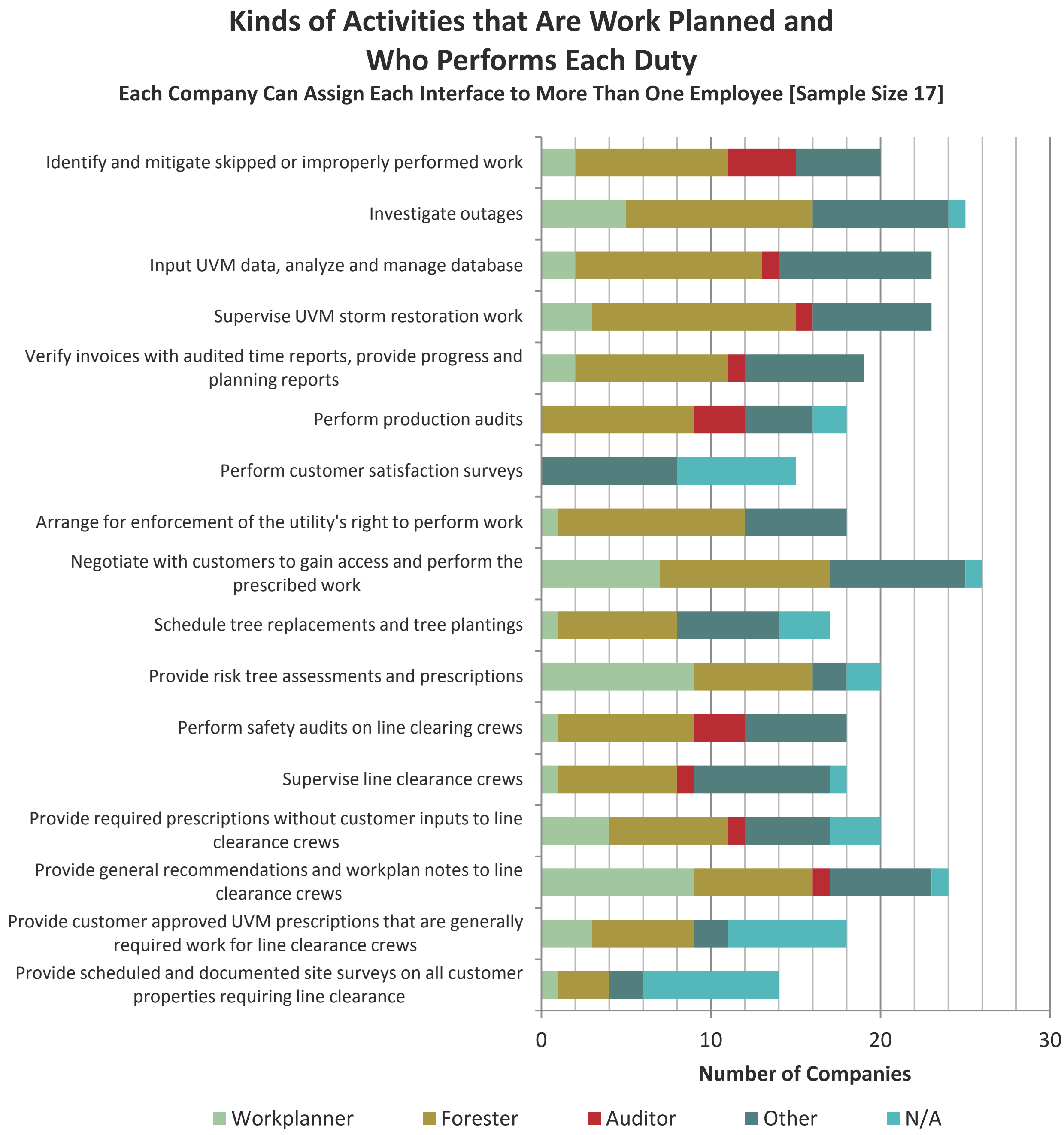


Figure 288: Kinds of Activities that Are Work Planned and Who Performs Each Duty

Comments on and Explanation of Other Kinds of Activities that Are Work Planned and Who Performs Each Duty
Our customer service department randomly picks customers to provide feedback on satisfaction surveys. The vegetation analyst does most of the data analyzing but our field foresters do quite a bit of data entry as well as analyze the data the analyst supplies.
Marketing and Communications Group
Other refers to external UVM Contractors.
Other equals Contractor General Foreman or Foreman.
Other = general foreman contractor management at utility
Operational productivity and safety audits are conducted by our field forestry supervisors and managers. Work planning and customer contact are conducted by our Forestry Technicians.

Figure 289: Comments on Kinds of Activities that Are Work Planned and Who Performs Each Duty

Customer Communication with Work-Planning Personnel

The next two tables contain reported data on communication between customers and work-planning personnel. The first table (below, this page) includes the comments that each company made about their data. The second table (next page) reports the recoded data.

Objective: Determine the extent which customers communicate with work-planning personnel.

Question #225: Please enter the AVERAGE ANNUAL NUMBER OF CUSTOMERS for each category. NOTE: In the comment box, please indicate if these numbers are estimates or calculated.

Comments on Customer Communications with The Utility	
3	Estimated
29	Above data is from Phone Board. Doesn't include direct calls to UVM personnel to their office or cell phone.
30	We communicate with many customers but it is not tracked in terms of giving a good estimated number for many of the above questions.
47	No Comment
83	No Comment
84	Estimated
91	We require 100% of tree removal forms.

Figure 290: Comments on Customer Communications with the Utility

Question #225: Please enter the AVERAGE ANNUAL NUMBER OF CUSTOMERS for each category.

Customer Communications with The Utility						
Company Code	**3**	**29**	**47**	**83**	**84**	**91**
Customers who sign permission to access their property to perform work	0	0	N/A	99%	13,000	0
Customers who sign permission when pruning is prescribed	0	0	N/A	90%	13,000	0
Customers who sign permission when herbicide work is prescribed	0	0	N/A	70%	N/A	0
Customers who sign permissions when removals are prescribed	95	7,000	DK	99%	1,500	6,000
Customers who call back when door hangers are left	15	N/A	DK	35%	5,000	10
Customers who respond to mailed notifications	0	N/A	DK	70%	N/A	5
Customers who respond to work-planner's knock on door	0	N/A	DK	2%	5,000	5
Customers who say no to performing any work	2	50	less than 10 per year	1%	40	2
Customers who say no to portions of work	2	N/A	82	2%	200	82
Customers who email their concerns	1	N/A		2%		4,300
Customers who compliment the work planning	2	N/A		20%		DK
Customers who complain about work planning	5	N/A		1%		DK
Customers who complain about tree work	5	350		5%		240
Customers who compliment tree work	1	N/A		2%		DK
Customers who request special work	0	3,300		10%		25,000
Customers who ask for and receive loads of woodchips	1	160		1%		DK

Figure 291: Customer Communications with the Utility

Work-Plan Data Collection and Format for Inspections and Prescriptions

Objective: To determine the detail required for inspections and prescriptions.

Question #226: From the following list choose the items that your planners are documenting in their inspections and whether the planning is completed on paper, electronically or both. Check all that apply.

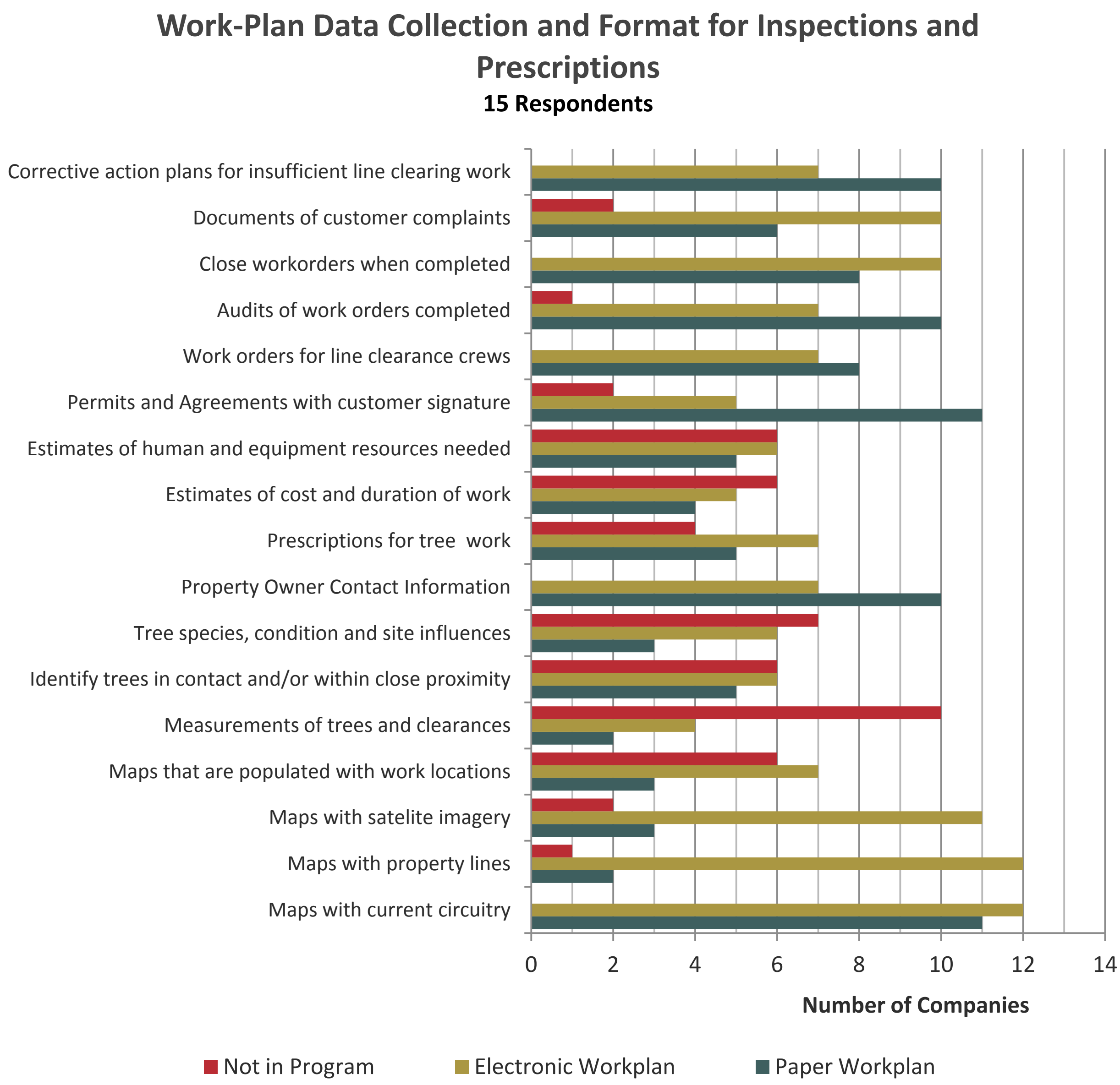


Figure 292: Work-Plan Data Collection and Format for Inspections and Prescriptions

Data Discussion of Work Planning Data Collected and Format of Documentation:

15 Companies responded to **Question #226**. The graph above reveals several things about workplan data capture.

1. All respondents use maps for current circuitry and most of those companies are using maps in both paper and electronic form (Category at bottom of graph). There was only one company using paper only and three using electronic only.
2. Less than half of the respondents have work locations on work order maps.
3. The most prevalent use of workplan documentation is a signed work agreement.
4. A majority of respondents do have tree prescriptions included in work-plans.
5. Work Orders are supplied to line clearance crews for most of the companies.

Conclusion: Work-plans often lack detail, such as tree species, clearance specifications, conditions, etc. Paper is still used most of the time as part of or as the only workplanning/inspection documentation.

HAZARD TREE PROGRAMS

For questions relating to hazard tree assessments and programs, RISK TREE and HAZARD TREE are used interchangeably. For the purpose of this benchmark this survey uses the following DEFINITION for hazard or risk tree. HAZARD or RISK TREES: Trees are hazardous and involve risks when the failure of one or more of their parts could result in property damage, personal injury and/or impacts to electrical lines.

Percent of Companies with a Hazard Tree Program

Question #227:

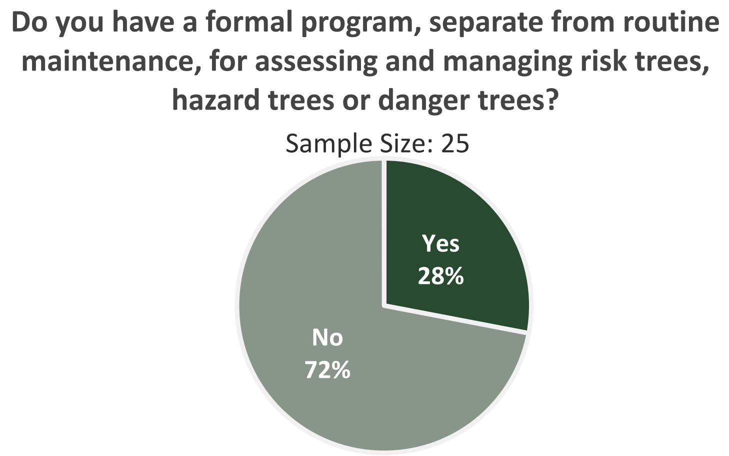


Figure 293: Percent of Companies with a Hazard Tree Program

This is a **5% decrease** from 2006 data.

Descriptions of Hazard Tree Programs

Question #228: Please provide your definitions for the following three terms: Hazard Tree, Risk Tree and Danger Tree

Descriptions of Hazard Tree Programs
Danger Tree: Dead, diseased, decayed, declining, tree that has a target - property, public, or Distribution System. **Hazard Tree:** Same as Danger Tree definition but more imminent in nature.
Hazard Tree: A hazard tree is a danger tree that has an unacceptable risk of failing before the next maintenance cycle.
Dead tree program for pines.
Hazard tree assessment is done during our routine patrols.
Hazard Tree is a tree with a flaw and a target (power line). **Danger Tree** is a tree that has a target (power line). We don't use the term "Risk Tree."
Hazard tree - Any dead/declining/damaged or excessively leaning tree that has the potential to contact the primary when it falls and cause a reliability issue and/or facility damage within the trim cycle. **Risk tree** - Critical removal profiles A. Directly affecting or evidence of affecting 2 or more phases B. Overhang or offset with potential of blow-in or dropping frond on 2 or more phases C. Directly affecting or evidence of affecting 1 phase
We use the ANSI 300, Part 7 definitions of hazard and danger tree and do not use the term risk tree.
Nothing in writing for distribution.
A tree - living or dead - in which its condition, its health, its species, the quality of its root system, its orientation and/or degree of inclination of certain portions, presents a risk of being uprooted or being susceptible to other damage that can compromise the reliability of the distribution network.
We follow the definition used ANSI A300, Part 7 Standard for **Hazard Tree** and **Danger Tree**. **Risk trees** in terms of rank of severity fall behind Hazard and Danger Trees. It is not used regularly and as the term reflects, it's a risk but not as likely to fail in the short term as a Hazard Tree or Danger tree.
Danger Tree - a tree considered a potential hazard to [Utility's] facilities positioned outside of the normally cleared right-of-way. **Hazard Tree** - a tree considered a potential threat to the safety and reliability of [Utility's] facilities growing within the normally maintained right-of-way. Risk Tree is same as hazard tree for [Utility].
Danger Tree: any tree which, through its geometry, if it fell could impact electrical facilities. **Risk Tree** - this term is not used. **Hazard Tree** - same as a Danger Tree except it is dead, dying or diseased, or has growth abnormalities which could contribute to failure.

Figure 294: Descriptions of Hazard Tree Programs

Hazard Tree Assessments

The next four questions probe the nature of tree assessments performed to identify trees as *Hazard or Risk Trees.* Specifically:

1. Are Trees outside of Easements Assessed for Hazard Conditions?
2. Are Trees outside Easement Assessed During Routine Inspections?
3. Are Inspections Performed by Walking 360 Degrees around Trees?
4. Do Work Planning Inspections on Hazard Trees Routinely Involve Special Tools?

Question #229:

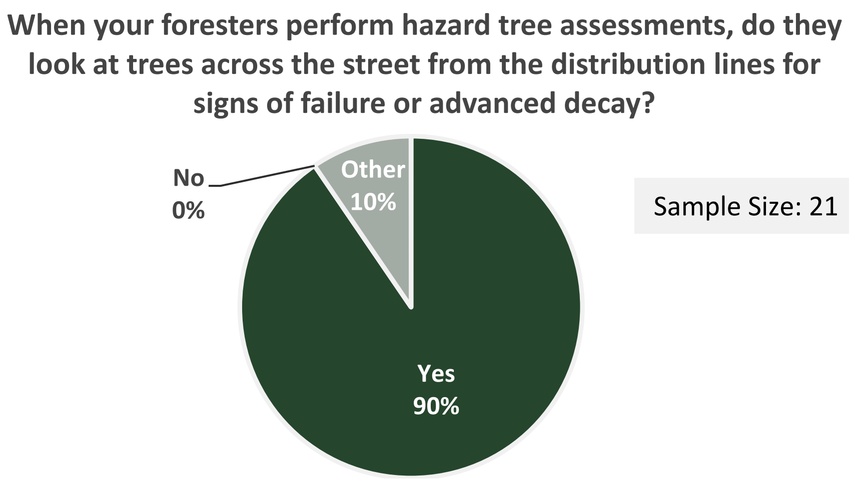


Figure 295: Are Trees outside of Easements Assessed for Hazard Conditions?

Comments on Assessments of Trees Outside of Wire Zone for Hazard Conditions
They are not directed to, but they might see it. [Other]
Yes, but not typically, majority is on wire side. [Other]

Figure 296: Comments on Assessments of Trees Outside of Wire Zone for Hazard Conditions

Question #230:

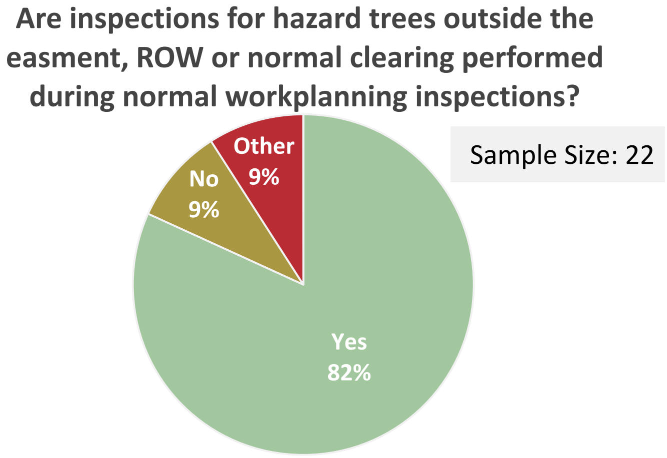


Figure 297: Are Trees outside Easement Assessed During Routine Inspections?

Comments on Whether Trees outside Easement Are Assessed During Routine Inspections
Both with normal workplanning inspections, as well as specifically to the Hazard Tree Program (separate from maintenance). [Other]
Limited rights to remove means limited observance of hazard trees outside of easement. [Other]

Figure 298: Comments on Whether Trees outside Easement Are Assessed During Routine Inspections

Question #231:

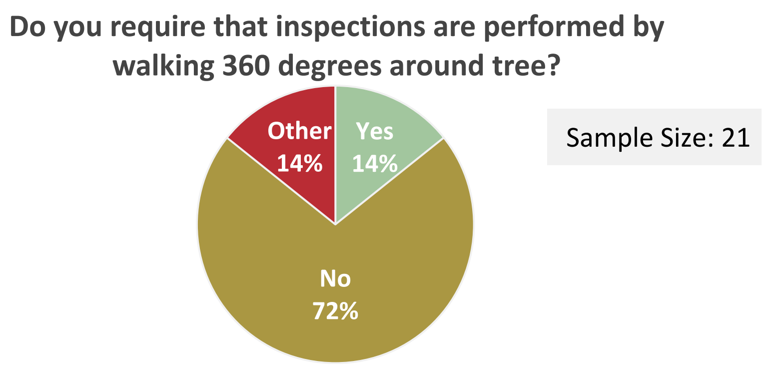


Figure 299: Are Inspections Performed by Walking Completely around Trees?

Comments on Inspecting Trees by Walking completely Around Them
This is the only thorough way for accurate inspection. [Yes]
Only dead trees. [Other]
If a defect is noted then that is a reason to do a 360 degree. [Other]
Most inspections are visual and viewed from a distance, but if it is determined that something is wrong with the tree based on appearance, then a more formal 360 degree inspection is sometimes conducted to diagnose the problem and see if tree removal is necessary to lessen the likelihood of the tree failing and making contact with our lines. We do realize that a 360 degree walk around is the

best way to get a total view of the tree and find any potential disease, wounds, root rot, etc but with size of our system, this is not always feasible so we do not require this on inspections. [No]

Figure 300: Comments on Inspecting Trees by Walking completely Around Them

Question #232:

Figure 301: Are Special Tools Routinely Used to Assess Hazard Trees?

Descriptions of Special Tools Used for Risk Assessment for Trees
Our contractors utilize a hazard tree assessment tool that helps to rank the relative risk the tree presents.
Tomograph, Hammers
Tree hammer to check density

Figure 302: Descriptions of Special Tools Used for Risk Assessment for Trees

Miles of Line Inspected Specifically for Hazard Trees Annually

Question #233: If you perform hazard tree assessments separate from your regular workplanning or inspection program, what percent of your miles/km of line are inspected specifically for hazard trees each year?

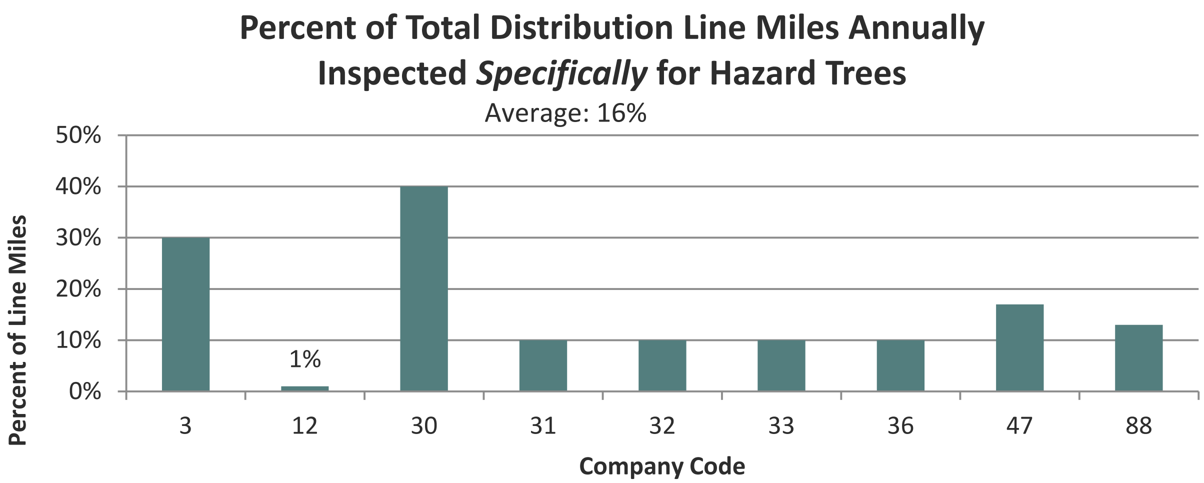


Figure 303: Percent of Total Distribution Line Miles Annually Inspected *Specifically* for Hazard Trees

Comments on Miles of Lines Inspected Annually for Hazard Trees
We base our HT Program on a "Worst Performing Circuit list". The number of circuits and line miles vary from year to year based on inventories.
Our independent hazard tree program is a new program that we are currently piloting and plan to ramp up in the coming years.
Mid-cycle inspection of mainlines only.
We remove dangerous trees accordingly to a choice of circuits identified for their bad continuity of service.

Figure 304: Comments on Miles of Lines Inspected Annually for Hazard Trees

Assessments for Other Targets besides Powerlines

Question #234:

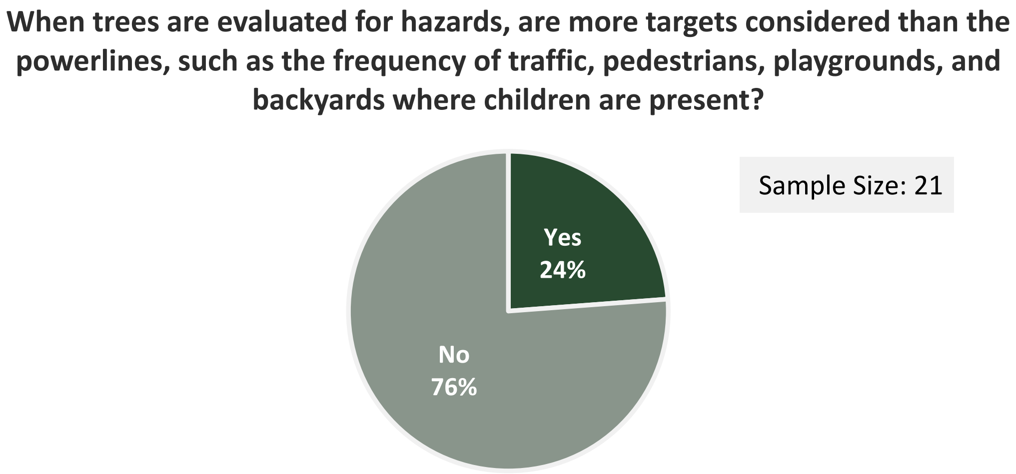


Figure 305: Assessments for Other Targets besides Powerlines

Targeting Trees in Good Health but a Threat by Proximity

Question #235:

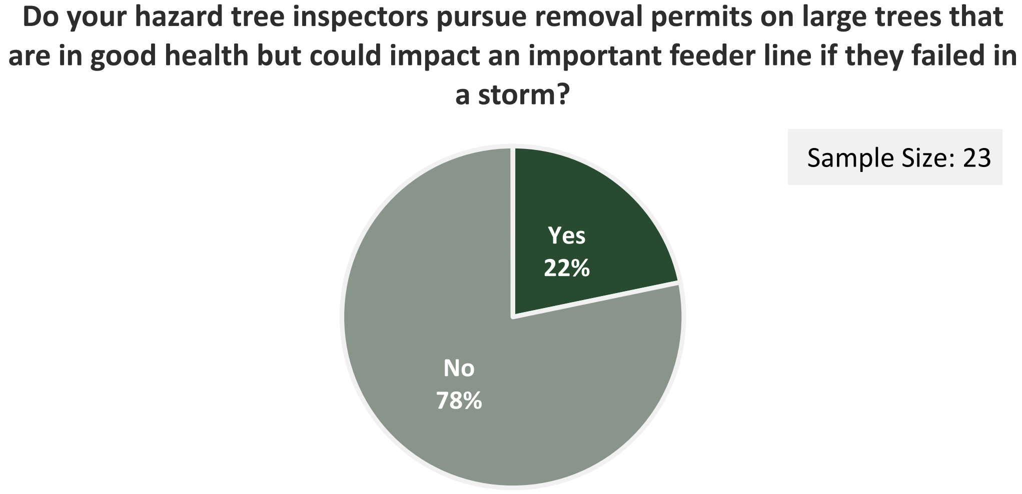


Figure 306: Targeting Trees in Good Health but a Threat by Proximity

Average Annual Number of Trees Removed to Storm Harden Distribution System
Very difficult to have a number but a lot of them are in very good health, but mechanically fragile due to their nature (species).
Estimate that around 2,000 trees a year fit into this category

Figure 307: Average Annual Number of Trees Removed to Storm Harden Distribution System

Tracking of Tree Species and Failure Type of Tree-Related Outages

A study of failed trees in northern California found approximately one third of urban tree failures are branches, one third are trunks and one third are roots.

Question #236:

Figure 308: Tracking of Tree Species and Failure Type of Tree-Related Outages

Comments on Tracking Causes of Tree-Related Outages

We are going to start to do this. We would like to contribute to the Tree Failure data base. We are somewhat restricted by available resources to accomplish this. We currently have an increased focus on reliability, so we believe we need to put more of an emphasis on this part of the process. [No]
Only on feeders. [No]
We will start in 2012. [No]
We have studied some of the trees to obtain a representative sample. [Yes}

Figure 309: Comments on Tracking Causes of Tree-Related Outages

Evaluation of Hazard Trees to Establish Priority of Action

Question #240:

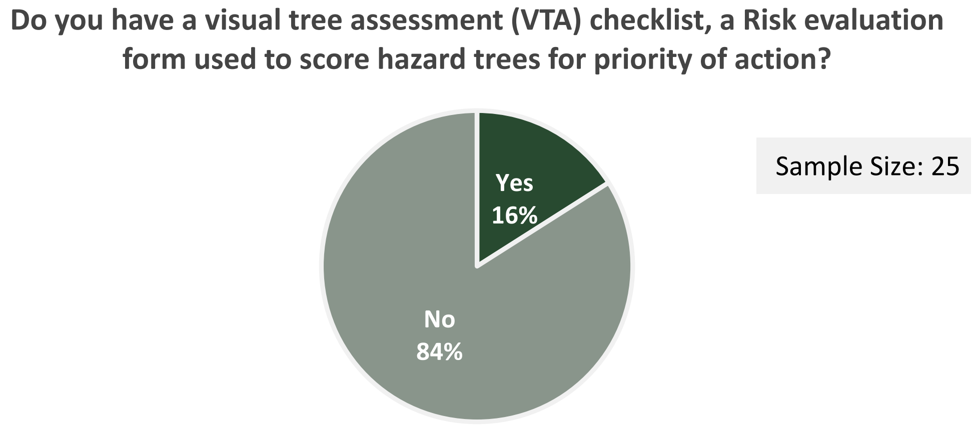


Figure 310: Evaluation of Hazard Trees to Establish Priority of Action

Description of your Hazard Tree Risk Evaluation Form
Our contractors utilize a hazard tree assessment tool that helps to rank the relative risk the tree presents.
It's part of the electronic program. It uses species, target and flaw as the criteria. Evaluation results in a numerical score.
Form captures risk profile and recommended countermeasures.
No hazard tree program.
But it's exceptional and only for exceptional trees.

Figure 311: Description of Hazard Risk Evaluation Form

Evaluating Healthy Trees as Hazards if Multiple Leaders Have Included Bark

Question #241:

Do you remove trees that have multiple leaders with included bark, that are otherwise healthy but pose a risk of failure during a wind event?

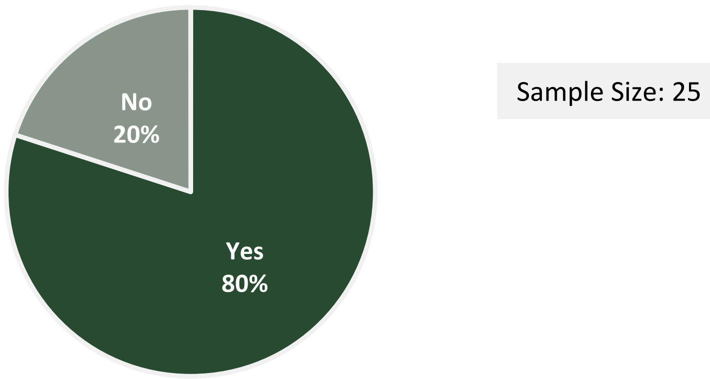


Figure 312: Evaluating Healthy Trees as Hazards if Multiple Leaders Included in Bark

Comments on Evaluating Healthy Trees as Hazards if Multiple Leaders Included in Bark
Co-Dom. Stemmed pines, maples, oaks are all hazard tree candidates.
Depends on situation.
We remove those trees or we remove overhanging branches of those trees.

Figure 313: Comments on Evaluating Healthy Trees as Hazards if Multiple Leaders Included in Bark

Increasing Clearance Distances for Trees with a lot of Overhang

Question #242:

As part of your HAZARD TREE PROGRAM, do you target trees with a lot of overhang that are above your clearance standard?

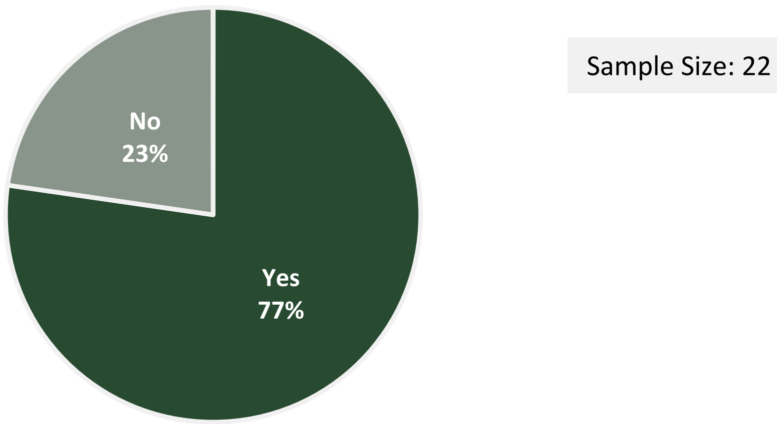


Figure 314: Increasing Clearance Distances for Trees with a lot of Overhang

Descriptions of your Approach to Managing Hazardous Overhang
Trees with overhang have the highest probability of contacting conductors and causing outages, therefore, if defined as hazardous tree, they are candidates for removal under Hazardous Tree Program.
We target removal of all hazardous overhang.
If the overhanging branches are dead or dying they would be removed during our routine annual patrols. Reliability projects that target specific circuit protection zones essentially remove all overhangs, including green healthy branches.
Depending on the circumstance. We may also look for engineered solutions such as Hendrix cable, line relocation or undergrounding
As part of specially funded ROW reclamation projects.
Yes, in those cases we often remove only overhanging branches.
If we deem the overhang to be a hazard to the line, then we may schedule some Skylining on that circuit to remove all the overhang that could fail and make contact with our lines.
Danger trees are identified, addressed and worked at the discretion of the individual operating companies or regions. Consideration for danger tree removal shall be made for those trees that are an imminent hazard or threat to [Utility] facilities. Danger trees may include, but are not limited to, trees that have severe lean or sweep, are dead, or have visible defect or damage. When cut, danger trees shall be cut as low as possible.
Trees with overhang have the highest probability of contacting conductors and causing outages, therefore, if defined as hazardous tree, they are candidates for removal under Hazardous Tree Program.

Figure 315: Descriptions of your Approach to Managing Hazardous Overhang

Use of Ladder or Aerial Lifts during Assessments of Hazard Trees

Question #243:

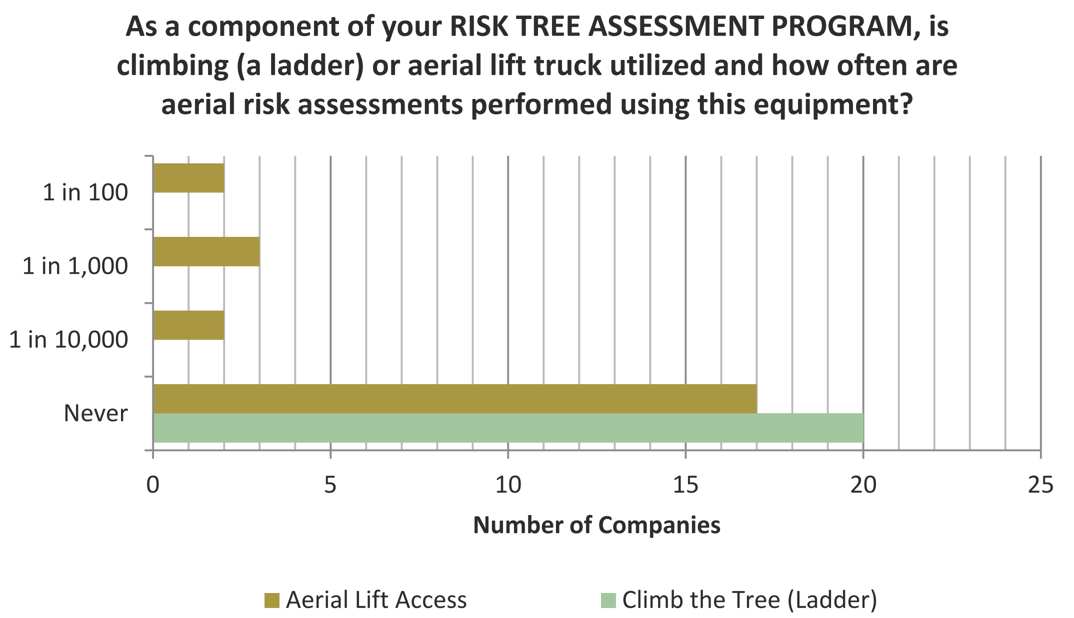


Figure 316: Use of Ladder or Aerial Lifts during Assessments of Hazard Trees

Fire Potential Tree Assessments

Question #244:

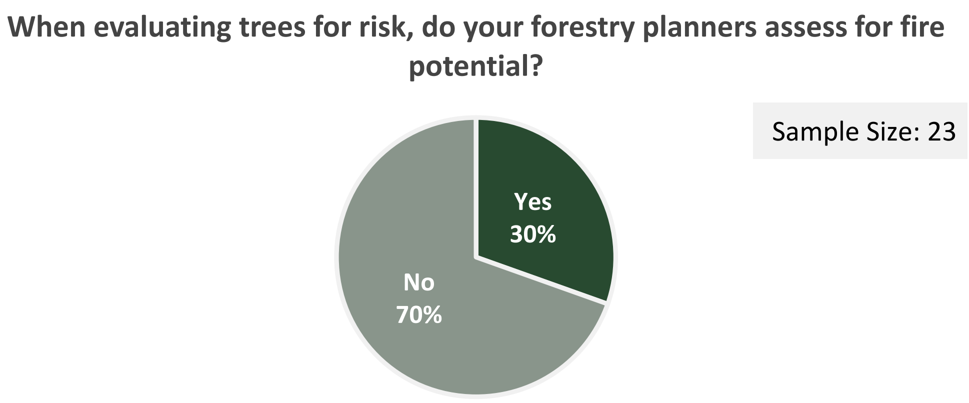


Figure 317: Fire Potential Tree Assessments

Descriptions of Fire Risk Assessment Process
Remediate the fuel within a 10 foot radius of the distribution pole.
Specific to geographic area.

Figure 318: Descriptions of Fire Risk Assessment Process

Confirmed Tree-Wire Conflicts Resulting in Wildfires

Question #245:

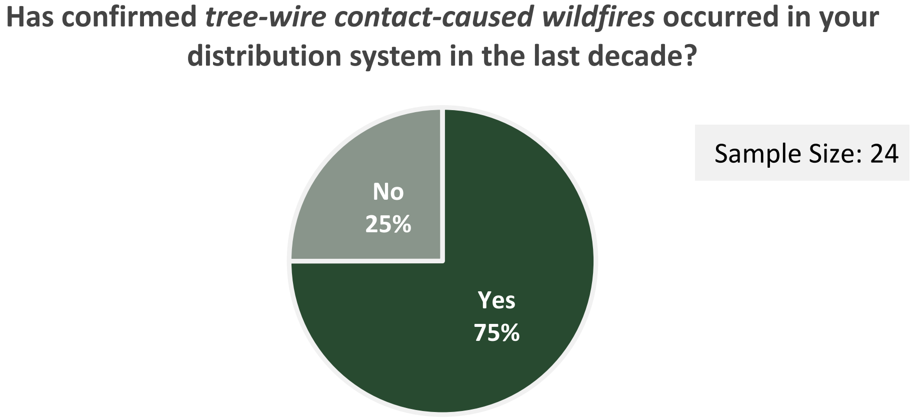


Figure 319: Confirmed Tree-Wire Conflicts Resulting in Wildfires

Descriptions of Wildfire Occurrences in the Last Five Years
Between 50-100 per year.
Numbers are confidential
Don't have the information
We have 6 incidents reported in the media between 2005 and 2010. There were trees falling into the powerlines causing small fires, usually only a few trees large.
There was one at a utility 150 miles from [City Name].
Various small fires have started because of trees/line contact in the last few years. Size has been limited to less than 50 acres.
We have had 2 larger fires in the last 10 years. Otherwise we have around 8-15 fire calls a year on the most part small fires (tree limbs burning in power line).
Some wildfires did occur in the last decades, but essentially caused by trees who fell on our conductors, very rarely by overgrowing contact. Occurrence is in the range of 10 per year. Over the last decade only one fire caused damage to buildings.
We do not track this data, but fires are started throughout our service area when tree wire contact has occurred.

Figure 320: Descriptions of Wildfire Occurrences in the Last Five Years

CUSTOMER SERVICE OBJECTIVES

Question #246: Rank the following CUSTOMER SERVICE OBJECTIVES by importance. 1 is the MOST IMPORTANT and 6 is the LEAST IMPORTANT. Only one choice per ROW

Two graphs have been made to display this data. One graph uses weighted averages with the most important on the top, decreasing in importance as you move down. The second graph is ordered in the same way, but it shows the percentage of companies that ranked each objective as 1, 2, etc.

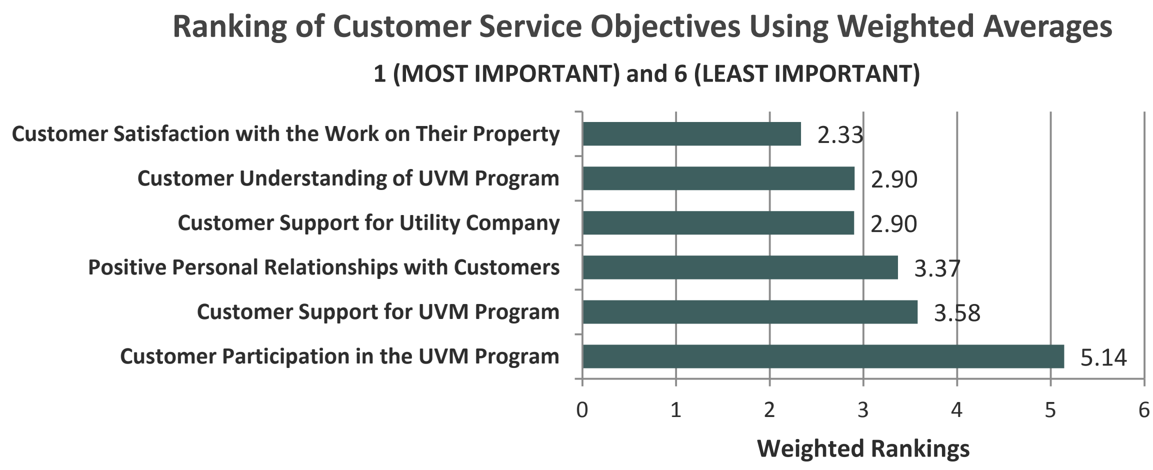


Figure 321: Ranking of Customer Service Objectives Using Weighted Averages

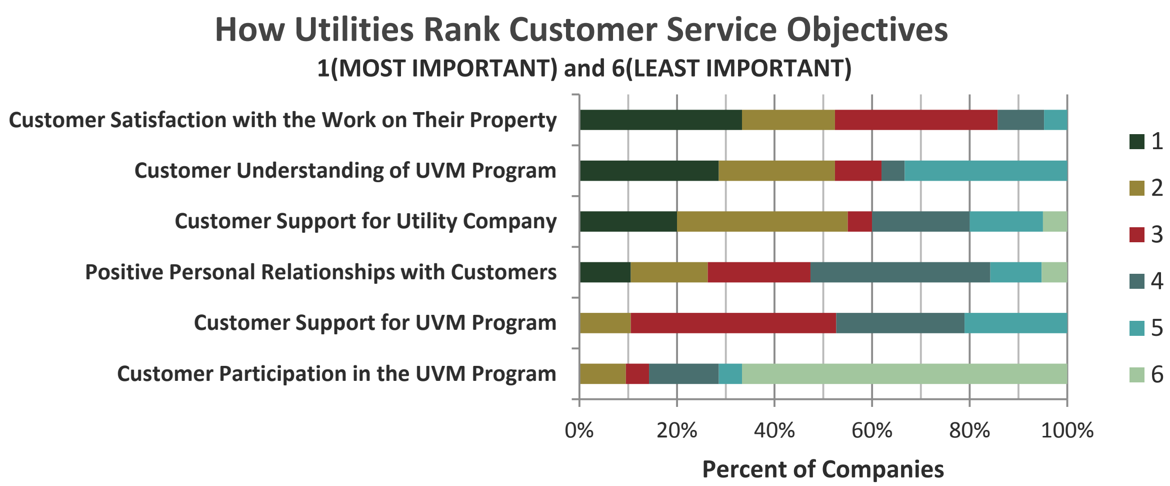


Figure 322: How Utilities Rank Customer Service Objectives

INITIATION OF ROUTINE WORK FOR DISTRIBUTION UVM

Question #247: Which of the following statements best describes how you normally initiate routine UVM work on property that is not owned by your utility company? Provide only one response.

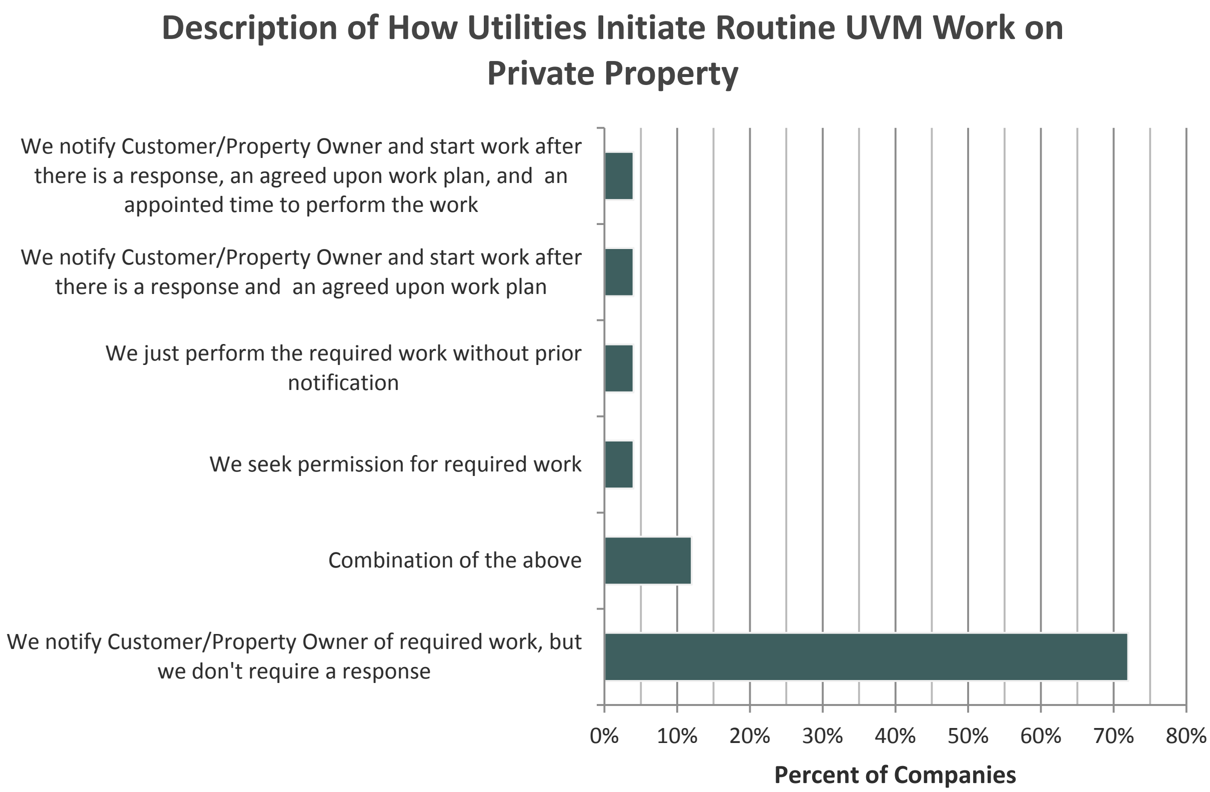


Figure 323: Description of How Utilities Initiate Routine UVM Work on Private Property

Comments on Initiating Routine UVM Work on Private Property
We notify for planned work. [Answer Given: *We notify Customer/Property Owner of required work, but we don't require a response*]
We give no appointed time, usually framed around the next year or so. Legislated requirement for permission to apply herbicides on private property. [Answer Given: *We notify Customer/Property Owner and start work after there is a response and an agreed upon work plan*]
We notify but do not require response for routine work. All removals and greater than normal clearance to be obtained should be agreed upon with customer. [Answer Given: *Combination of the above*]
We inform (ads in newspaper) for pruning; we seek permission for tree removal and brush cutting. [Answer Given: *Combination of the above*]
Notify first, seek permission, and then go ahead if contact cannot be made. [Answer Given: *Combination of the above*]
We require permission if tree removal is planned. [Answer Given: *We notify Customer/Property Owner of required work, but we don't require a response*]

Figure 324: Comments on Initiating Routine UVM Work on Private Property

CUSTOMER NOTIFICATIONS

Methods Used to Notify Customers of Impending UVM

The objective of this question is to discover how utility companies are notifying their customers of upcoming work. The Industry has identified 'touch points' that utility companies use to communicate with the customer on UVM activities. Notification has been the most common method. It is applied in a variety of ways.

Question #248: Which of the following notification methods do you employ, what are their efficacies, and how much in advance of work being performed are customers notified?

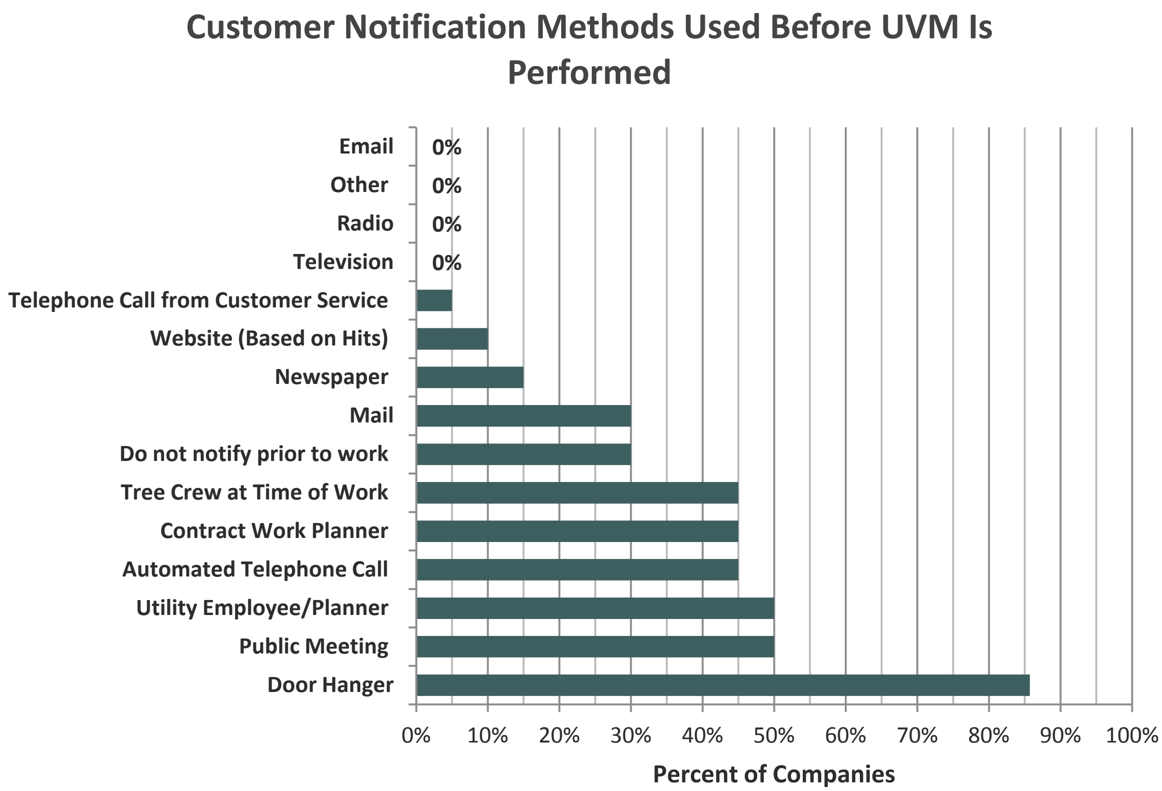


Figure 325: Customer Notification Methods Used Before UVM Is Performed

Comments on Notification Methods
We use door hangers for all planned activity.
Tree contractor leaves door cards generally.
Notification is not conducted during storm response.
Door hanger less than 1 % (max.: 19,000 per year). When we meet public, we try to meet municipal employees, professional in the "green business" but less than 1%.

Figure 326: Comments on Notification Methods

Efficacy of Customer Notification Methods

In **Question #248**, each participant was also asked to supply the *Impact of Notification on Customer Perception* (4 rating categories and one category of DO NOT KNOW were supplied). The results are displayed on the next two graphs.

The first is a bar graph of weighted averages with the highest (most successful) methods at the top and the second shows how many companies rated each method in each ranking category.

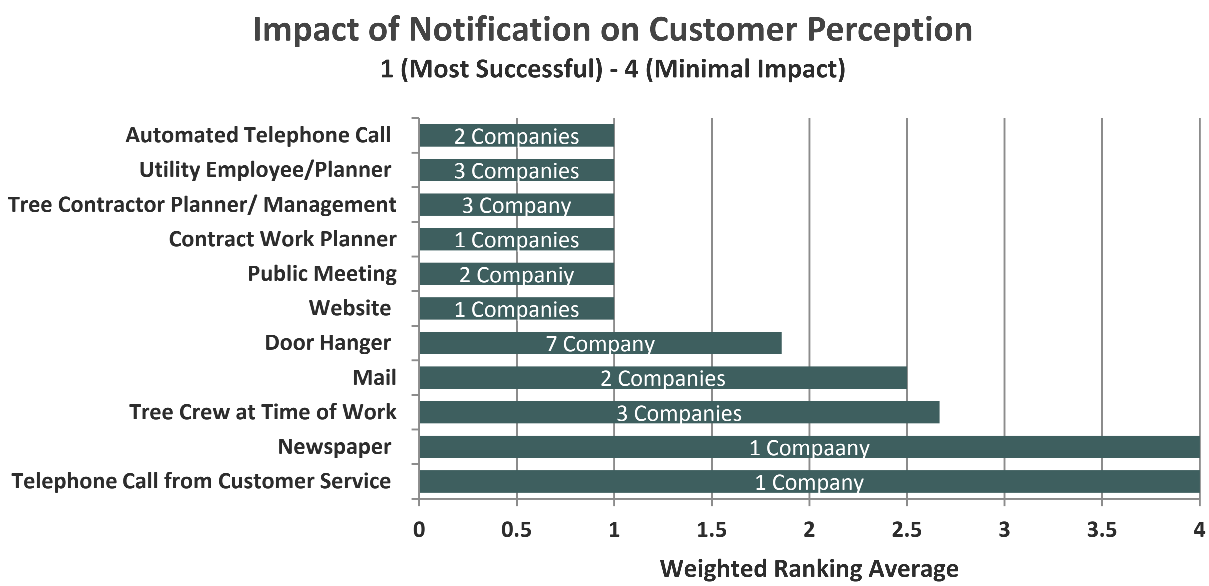


Figure 327: Impact of Notification on Customer Perception

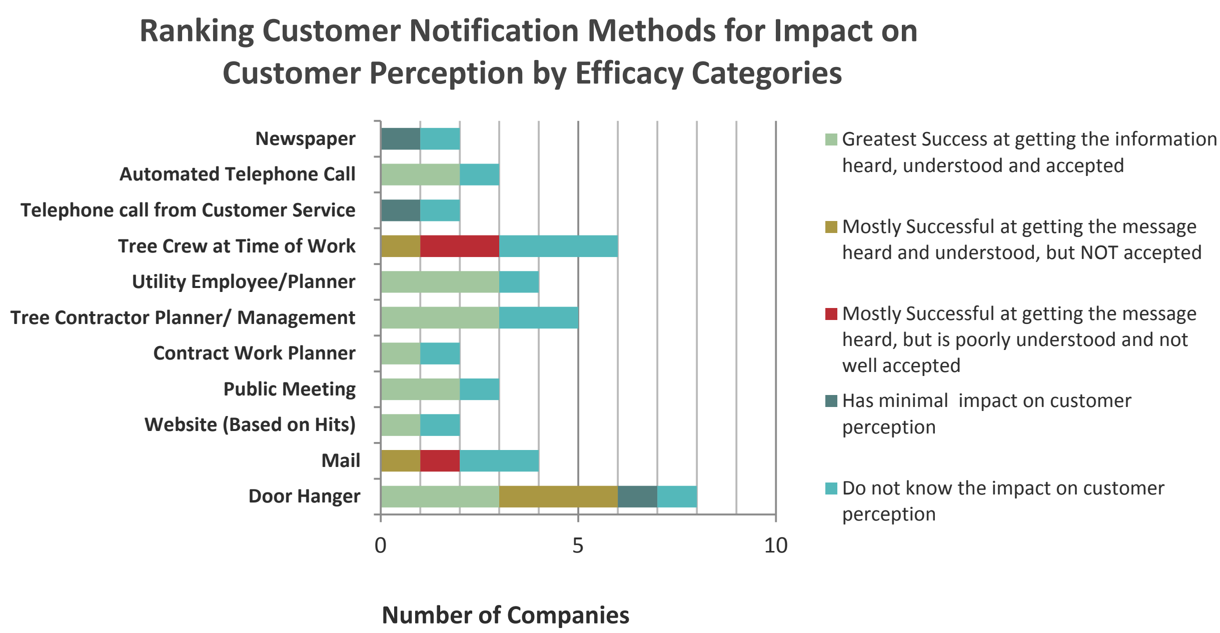


Figure 328: Ranking of Customer Notification Methods by Number of Companies

Average of Advance Notice for Each Notification Method Used

In **Question #248**, each participant was also asked to supply the *Average time of advance notice.* The results are displayed on the next 11 graphs. The number in parentheses is number of companies reporting.

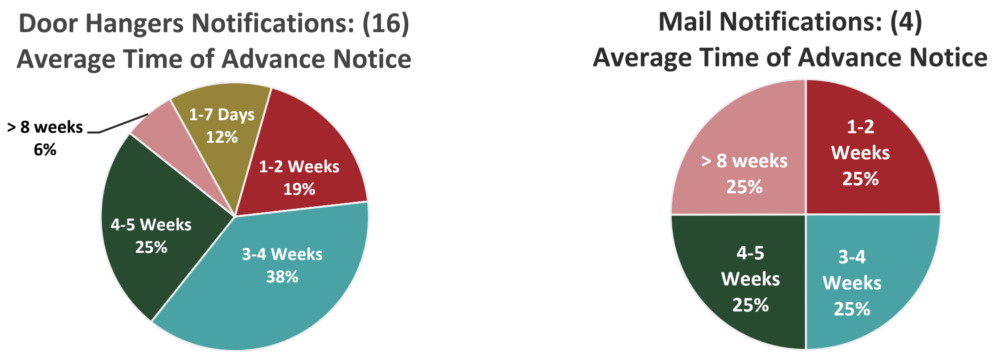


Figure 329: Door Hangers Notifications and Mail Notifications: Average Advance Time

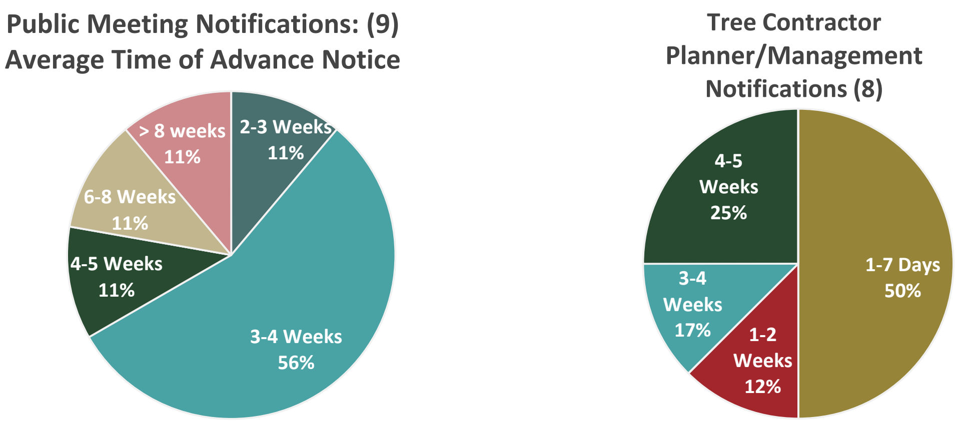


Figure 330: Public Meeting Notifications and Tree Contractor Planner/Management Notifications: Advance Time

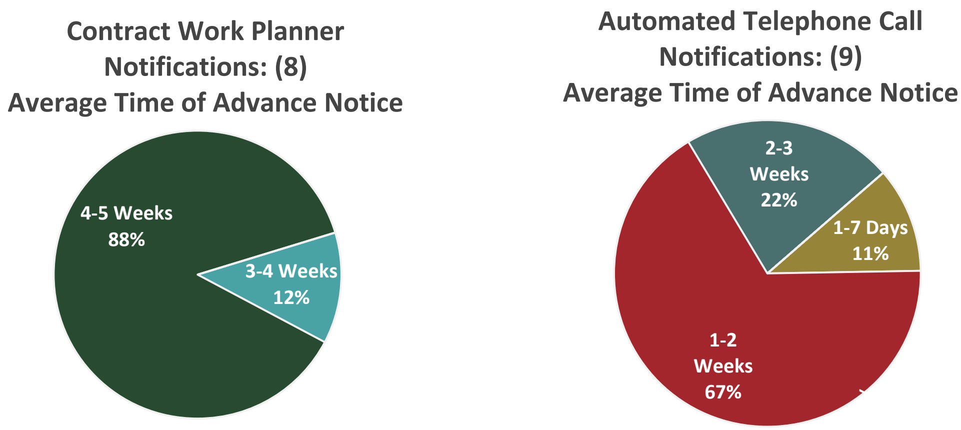


Figure 331: Contract Work Planners Notifications and Automated Telephone Call Notifications: Advance Time

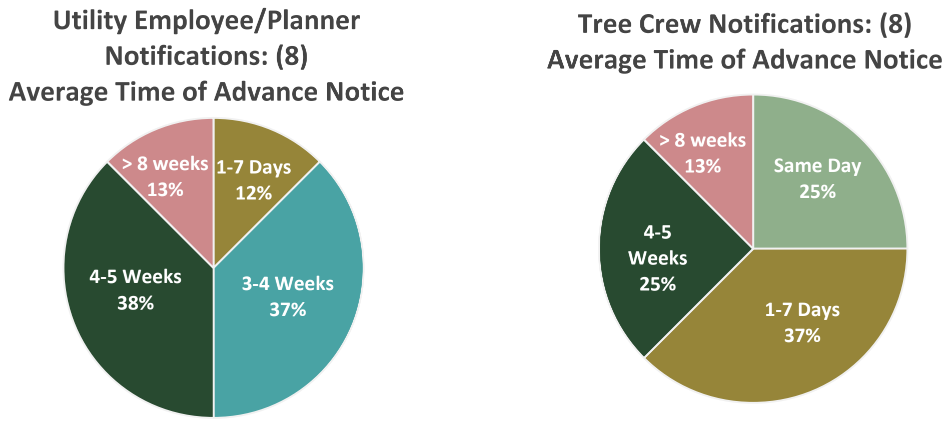


Figure 332: Utility Employee Planner Notifications and Tree Crew Notifications: Average Advance Time

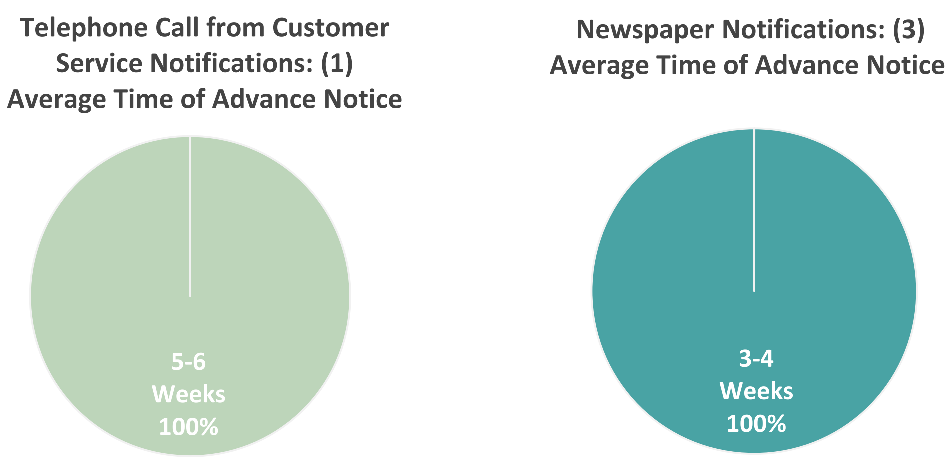


Figure 333: Telephone Call from Customer Service Notifications and Newspaper Notifications: Advance Time

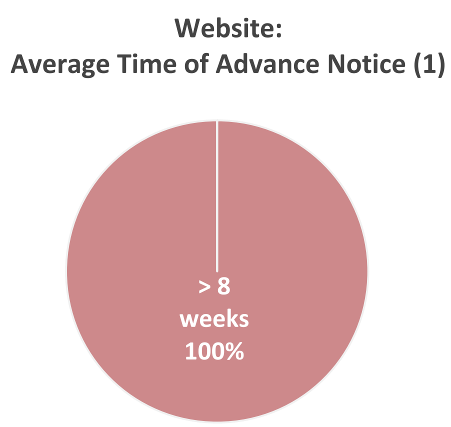


Figure 334: Website: Average Time of Advance Notice

Customers Notified by Each Method

In **Question #248**, each participant was also asked to supply the *Percent of Customers Notified by this Method.* The results are displayed on the next graph. The methods that notify the greatest number of customers are on the bottom of the graph decreasing as you move up.

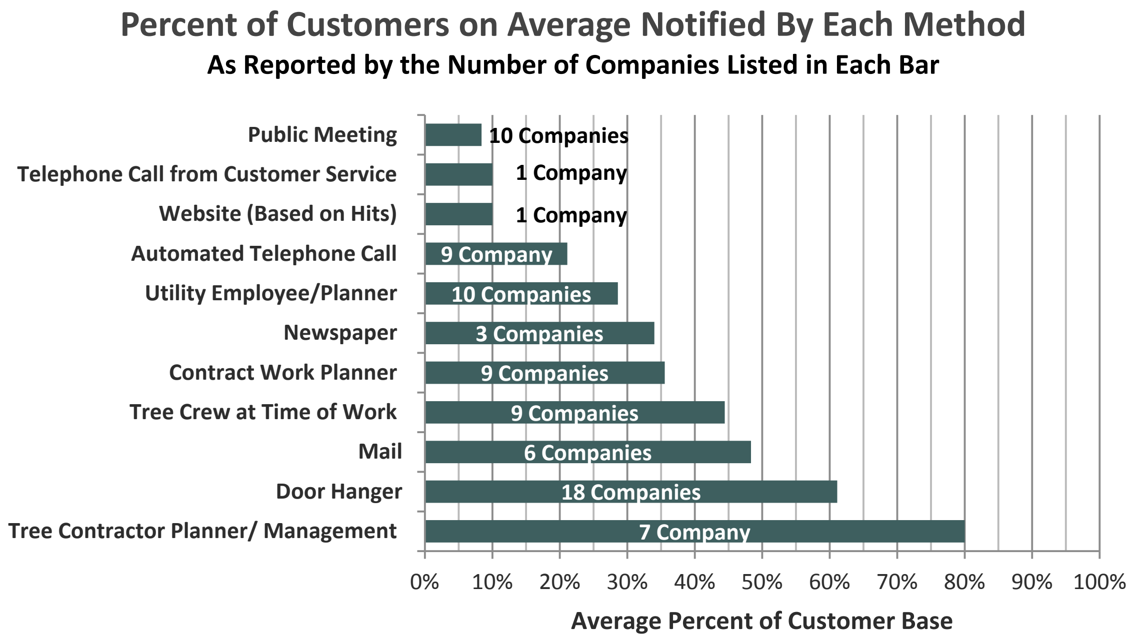


Figure 335: Percent of Customers on Average Notified By Each Method

REFUSALS TO ALLOW UVM TO BE PERFORMED

Tracking the Number of Refusals to Allow UVM to Be Performed

Question #251:

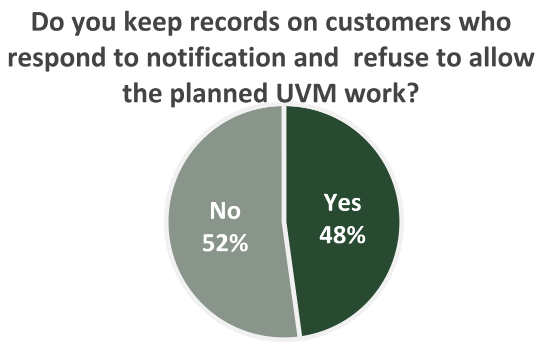


Figure 336: Track Number of Refusals to Have UVM Performed

Comments on Tracking Refusals
Most refusals are resolved after an explanation to the customer.
Not tracked.
The refusal numbers in the previous question are "escalated" issues to VM Department. The contract crews do not track "common" refusals.
We do not track to this level of detail.
Our customer refusals are not tracked in a way that makes answering this question possible.
Refusals on distribution are very rare.
No idea but estimates are <1% and very few are not worked out with customer.
We do track some of the refusals but it is very informal.
Identifications clustered together

Figure 337: Comments on Tracking Refusals

Resolution of Refusals

Question #254: What percent of your refusals are resolved during the following stages of UVM?

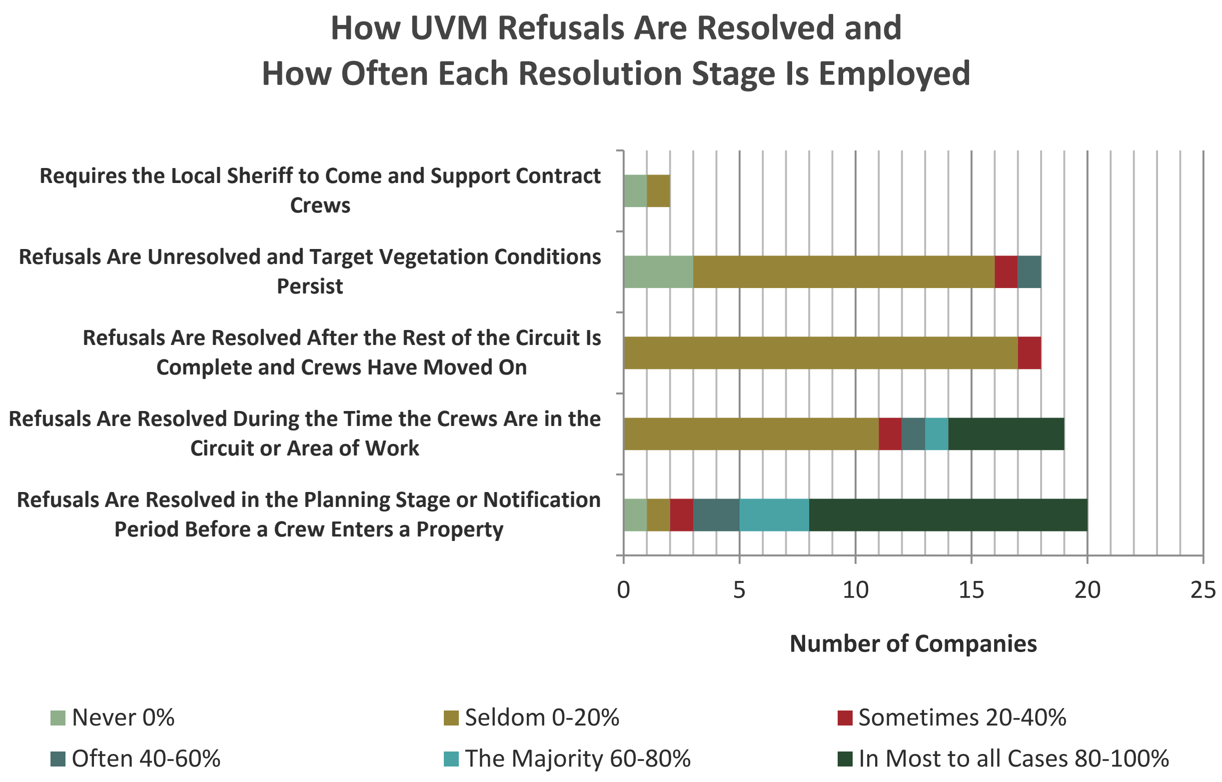


Figure 338: How UVM Refusals Are Resolved and How Often Each Resolution Stage Is Employed

Responsibility of Refusals Resolutions

Question #256: What percent of your refusals are resolved by the following positions or entities?   NOTE: One response per row.

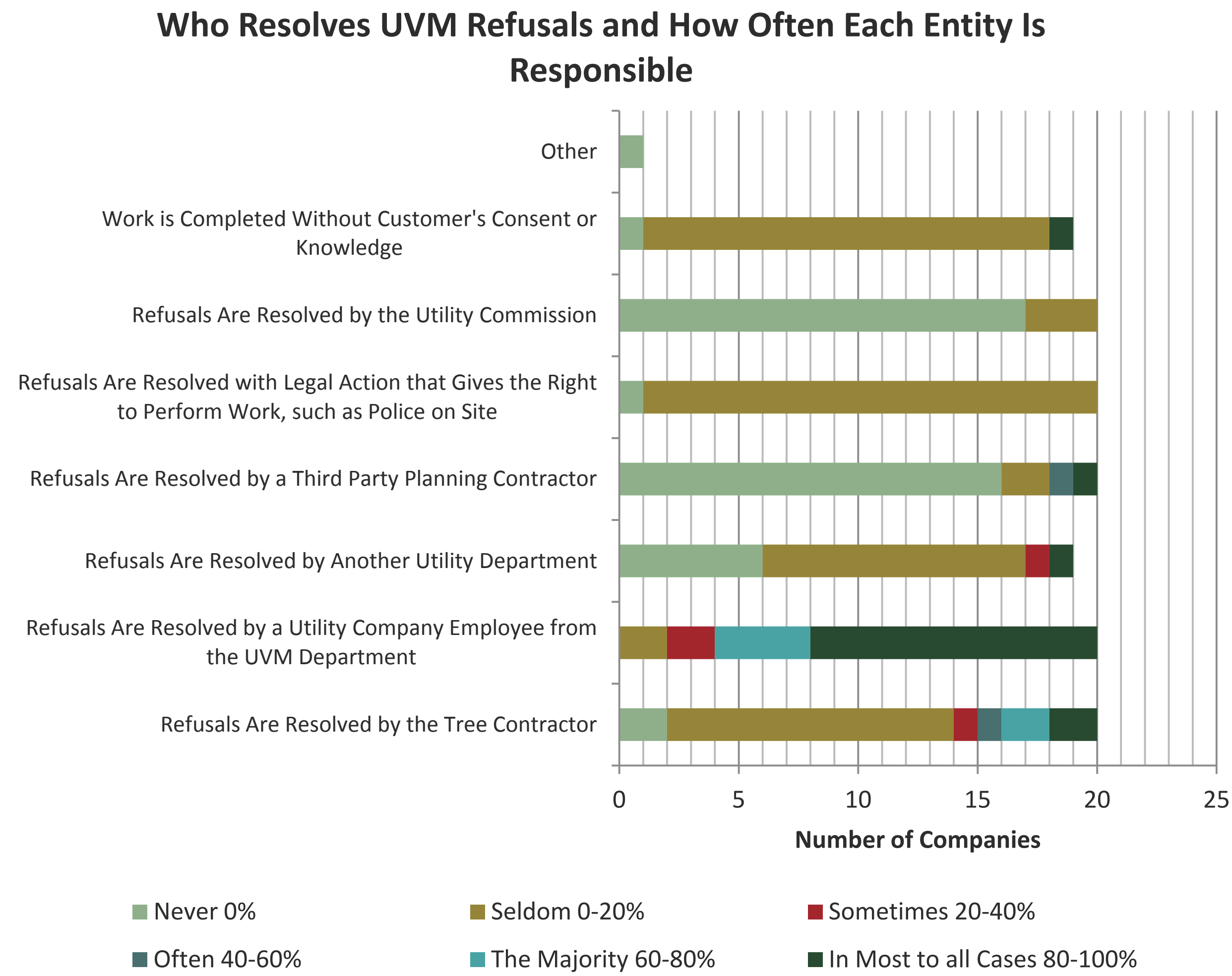


Figure 339: Who Resolves UVM Refusals and How Often Each Entity Is Responsible

Comments on Responsibilities for Refusal Resolution
Work is only completed without consent when efforts to contact the landowner have failed, usually absent landowners.

Figure 340: Comments on Responsibilities for Refusal Resolution

Reasons Customers Respond to Notifications

Question #257: For what reasons, besides refusals, do customers respond to notifications?

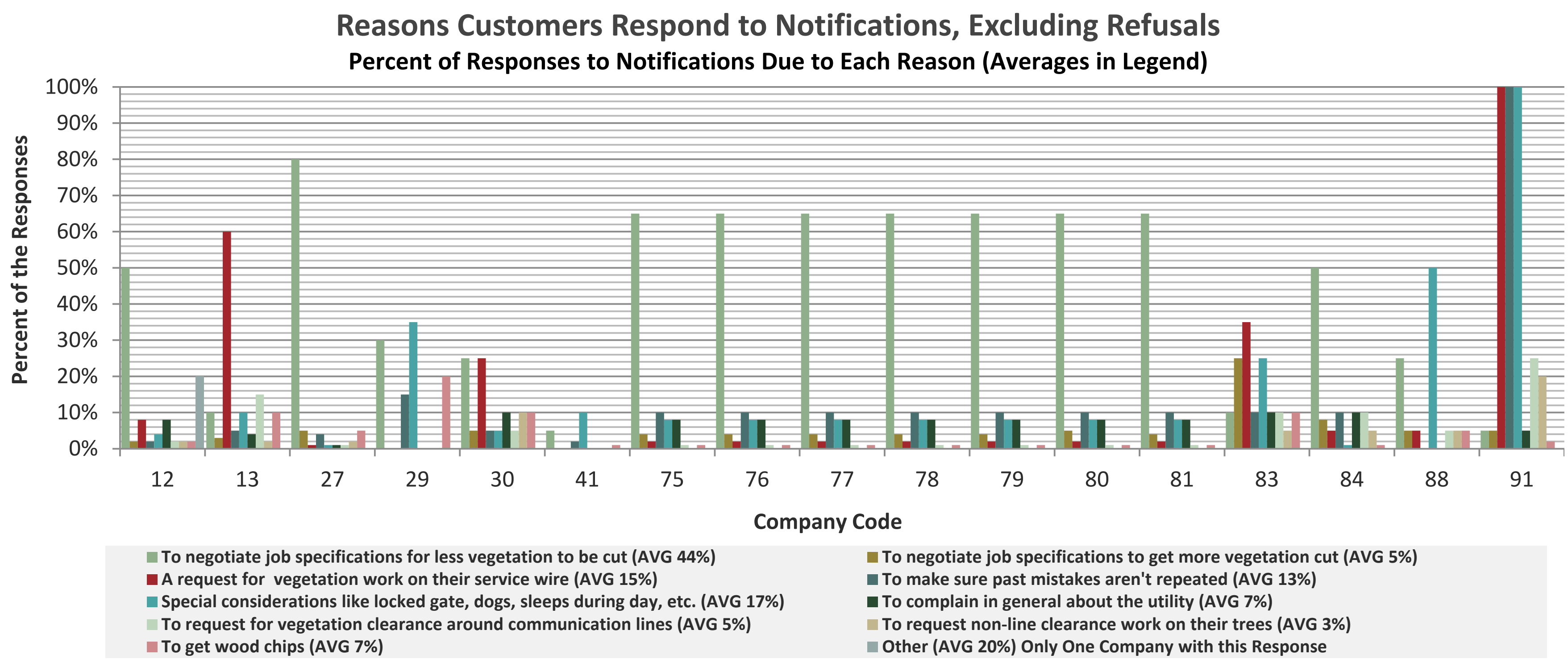


Figure 341: Reasons Customers Respond to Notifications, Excluding Refusals

Other Reasons Customers Respond to Notifications
Herbicide related refusals ~20%

Figure 342: Other Reasons Customers Respond to Notifications

Percent of Customer Base that Refuses to Allow UVM

Question #258: What percent of your total customer base, in your estimation, refuse initially to allow specified work?

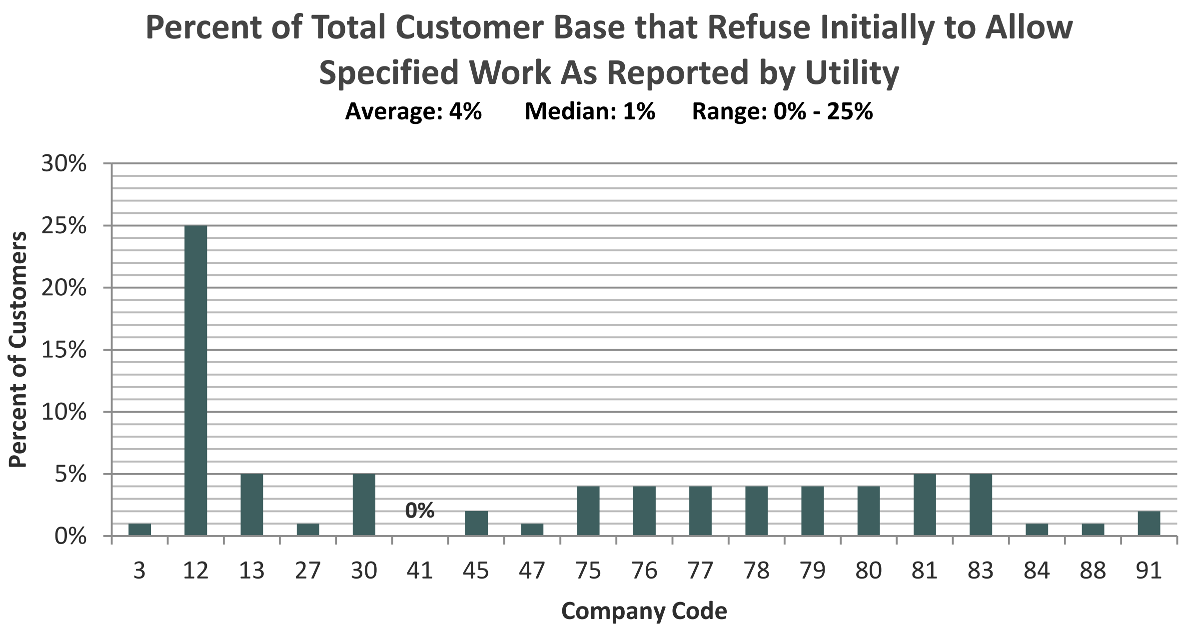


Figure 343: Percent of Total Customer Base that Refuse Initially to Allow Specified Work As Reported by Utility

RELATIONSHIP WITH CUSTOMERS

Question #259:

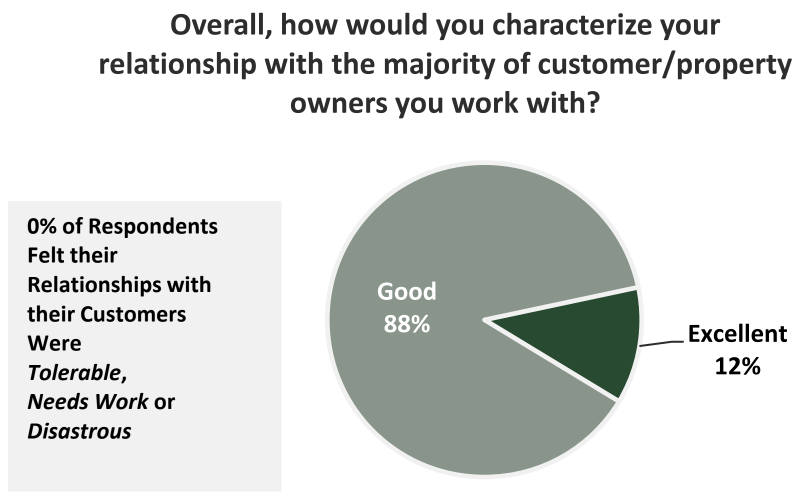


Figure 344: Characterization of Relationship with Customers

COMMUNICATIONS BETWEEN TREE WORKERS AND CUSTOMERS

Question #260:

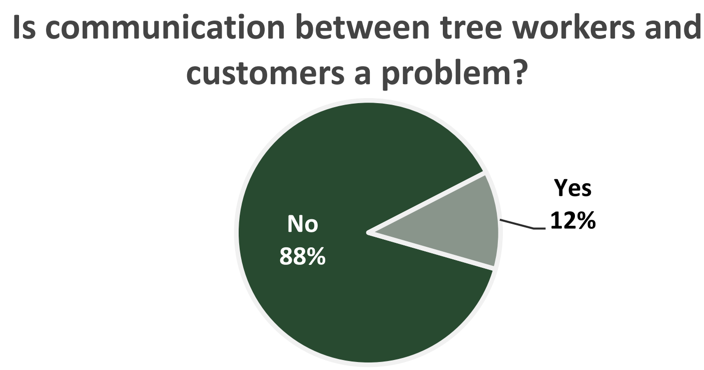


Figure 345: Communication between Tree Workers and Customers

Comments on "What are the communication issues and what are your best remedies?"
We have a program where company employees covertly ask crew question pertaining to line clearance operations.
Non-English speaking workers. Tree contractor is required to have a crew member or foreman that is English speaking.
Often crews speak a different language or do not have training or skills in speaking with customers.
Our notifiers are not the same people as the tree crew and this sometimes results in a difference in expectations. Tree workers are encouraged to contact the notifier to seek clarification on the work package.
Occasionally language barriers.
Some crews have English speaking limitations, but we are working to ensure that every crew has one well spoken English crew member.

Figure 346: Comments on "What are the communication issues and what are your best remedies?"

PUBLIC UNDERSTANDING OF INDUSTRY STANDARDS

Question #261: Do you think there is a "disconnect" (lack of understanding) between industry standards and what your customers/property owners and local agencies require you to do when performing UVM?

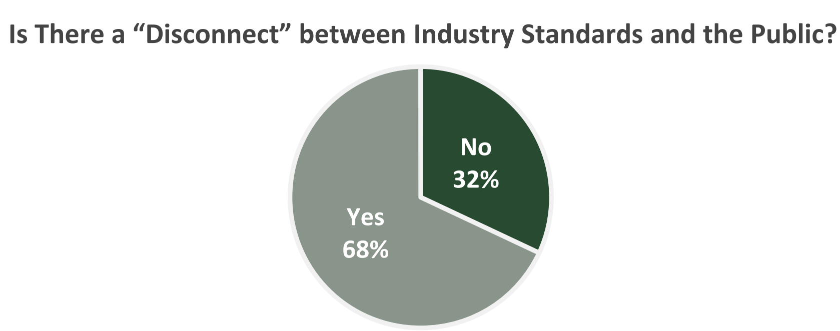


Figure 347: Is There a "Disconnect" between Industry Standards and the Public?

Public perception has improved slightly since 2002 for Distribution UVM. In 2002 **72%** of utilities felt there was a "disconnect" with the public. In 2006 this decreased to **67%.** Today, in 2011, it remained similar to the 2006 results with **68%.**

Comments on the Nature of the "Disconnect" with Public
Customers seldom understand the "V" trees and would rather see them "topped".
Do not think customers understand we have an obligation to provide reliable service and trees can interrupt that service.
Ownership of trees, hazard and reliability issues, lack of understanding of preventative maintenance.
Resistance to proper pruning techniques as opposed to improper techniques such as shearing tipping and topping.
Customers often think a tree has to be touching the conductor to be a problem; they don't understand concepts around minimal clearances by voltage and line configuration and cycle length. Customers are happy to see us removing vegetation following storms to restore service but often refuse even basic clearing of trees and brush as a preventative measure. Maintenance cycle - customers often ask - why not just take off a few branches and come back next year? Customers don't understand arboricultural target pruning, drop crotch pruning for tree health and feel more is taken than necessary when it is taken for tree structure strength and health.
Why wasn't I told you had these ROW rights before I bought the house? Local agencies are still trotting out Shigo tree trimming practices and Tree species to be planted under power line like it is the 70's and we cannot trim for the health of a tree when trimming for the health of the tree needed to start 20 years prior.
Clearance issues and types of cuts...
The amount of clearance needed for a primary line vs. a triplex service line and the removal of fast growing trees under the higher voltage power lines.
It's getting better and better, but in general: Our pruning cycle is often perceived too long, and the result of the activity, too intense. We can also report that our various clienteles grant to trees a very different importance accordingly to their origin, or their culture. As an example: the urbans are more sensitive to the tree than the countryman; the English speaking are more sensitive than French speaking. And urban moved in the countryside wishes a quality of service as impeccable as in the city, while keeping the forest character of his new environment. Quality of the electric service: the complaints of this nature are among the most numerous but the subject is not carried in the media. Quality of the work done: the aestheticism of the pruning is the object of less numerous complaints but more frequently carried in the media; Also forgetting collection of debris is the object of complaints.
Customers are sometimes unaware of state & local guidelines.
They do not always understand why we must trim certain trees as we do. Especially the u or v shape cuts made for trees directly under the line.

Figure 348: Comments on the Nature of the "Disconnect" with Public

ANNUAL UTILITY VEGETATION MANAGEMENT INQUIRIES

The next four questions will involve the number of CUSTOMER SERVICE CALLS RECEIVED by your utility on an annual basis. Specifically, you will be asked to supply amounts for the years 2008, 2009 and 2010. Customer Service Calls will be separated into the following categories: Total calls, UVM related calls, UVM calls related to notification of work to be performed, and complaints.

Question #262 asked for the number of annual customer service calls. Very few participants provided an answer.

Question #263: How many of these annual customer service calls are Customer/Property Owner inquiries regarding trees and power-lines (UVM related calls)? This would include such things as requests to inspect trees, or other general inquiries related to your activities.

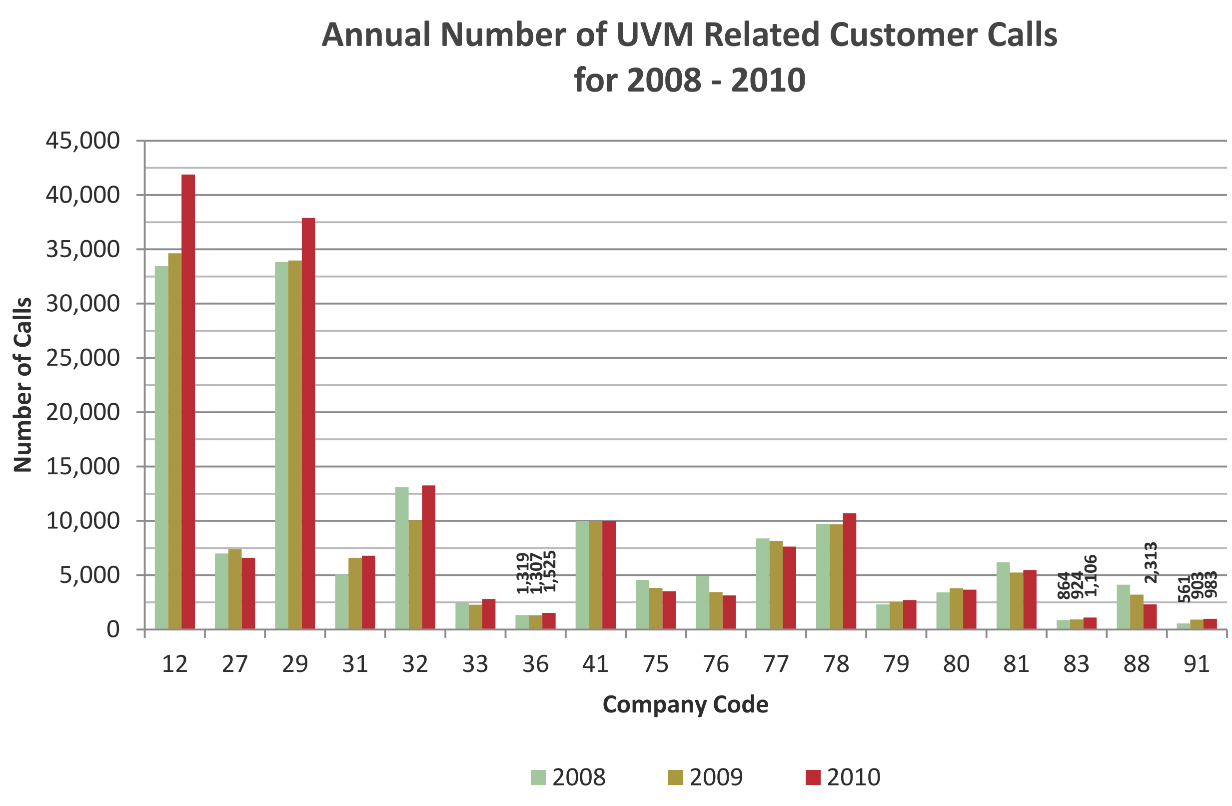


Figure 349: Annual Number of UVM Related Customer Calls for 2008 – 2010

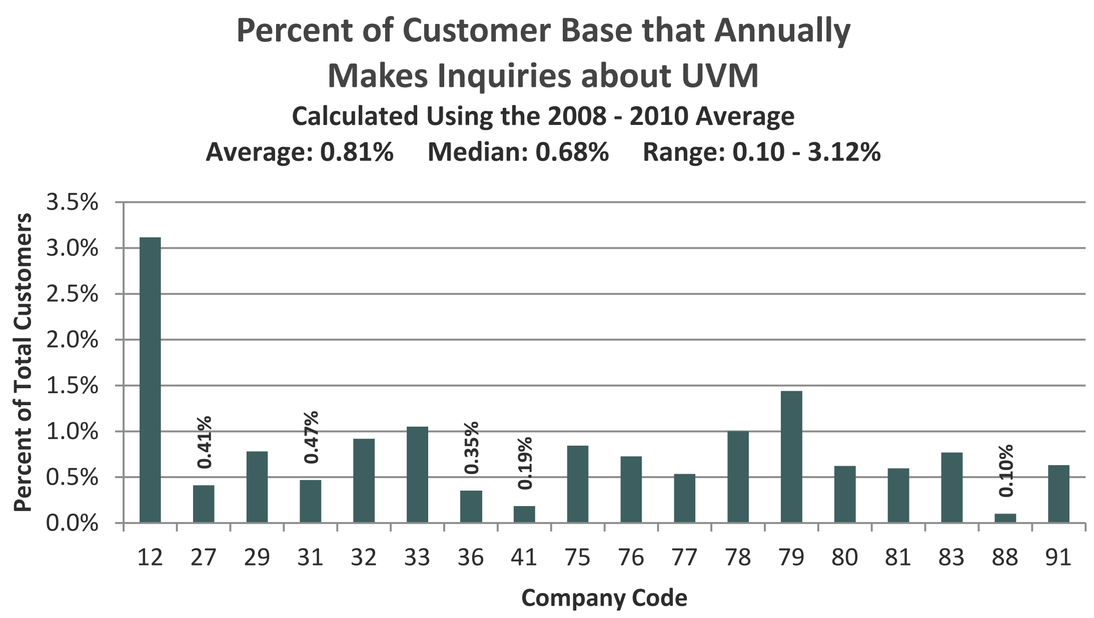


Figure 350: Percent of Customer Base that Annually Makes Inquiries about UVM

ANNUNAL UVM RELATED COMPLAINTS

Question #265: How many the Customer Service UVM Related calls are complaints?

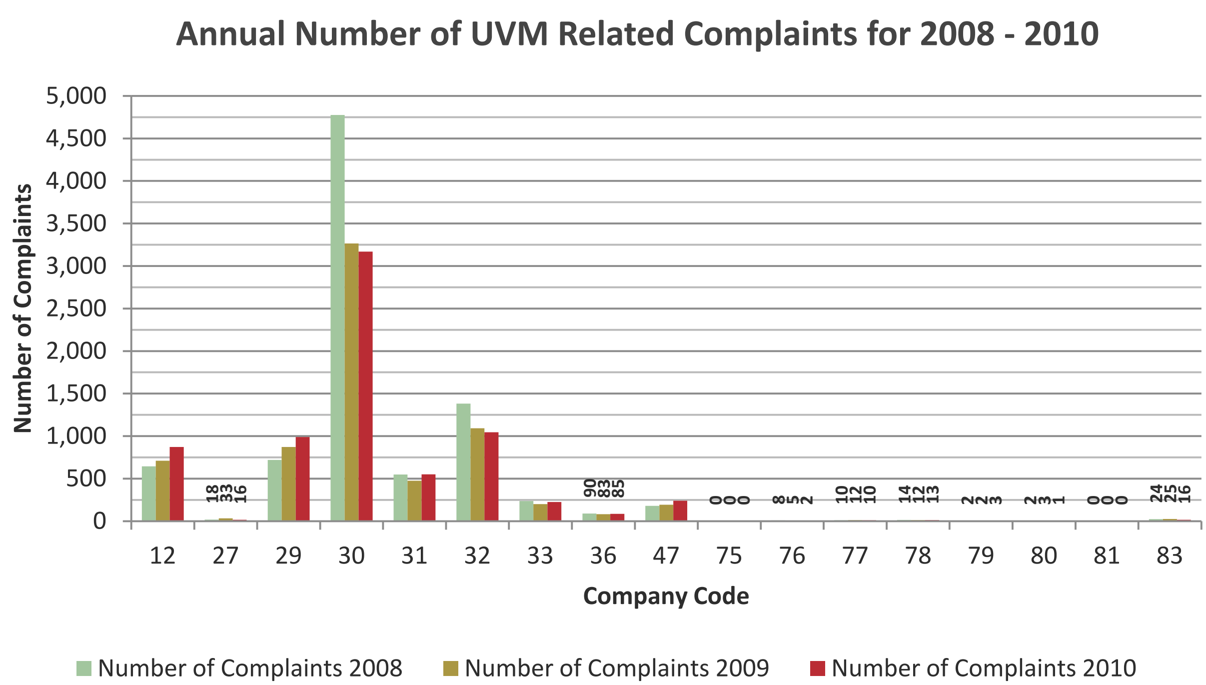


Figure 351: Annual Number of UVM Related Complaints for 2008 - 2010

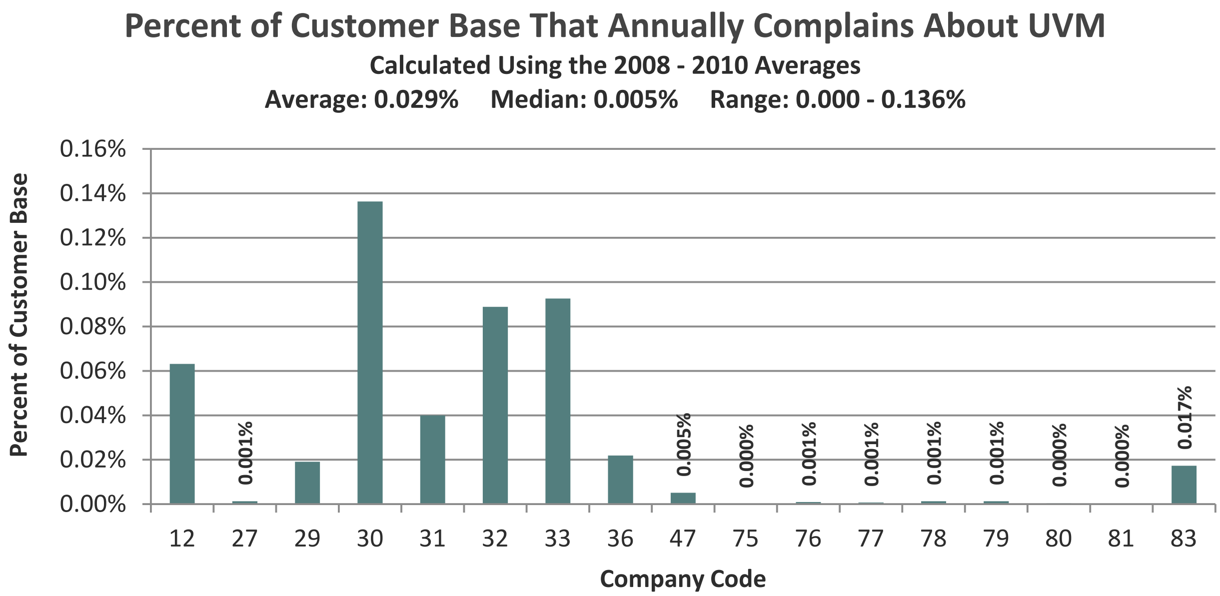


Figure 352: Percent of Customer Base That Annually Complains About UVM

RESPONSE TIME FOR UVM RELATED CALLS

Question #266: In a given time frame, what percent of Customer UVM related inquiries do you respond to by going to the address/problem location and inspecting the vegetation/problem? For example: We respond on location to 50% of our customer service requests within 24 hours. NOTE: The sum of all the answers should equal 100%.

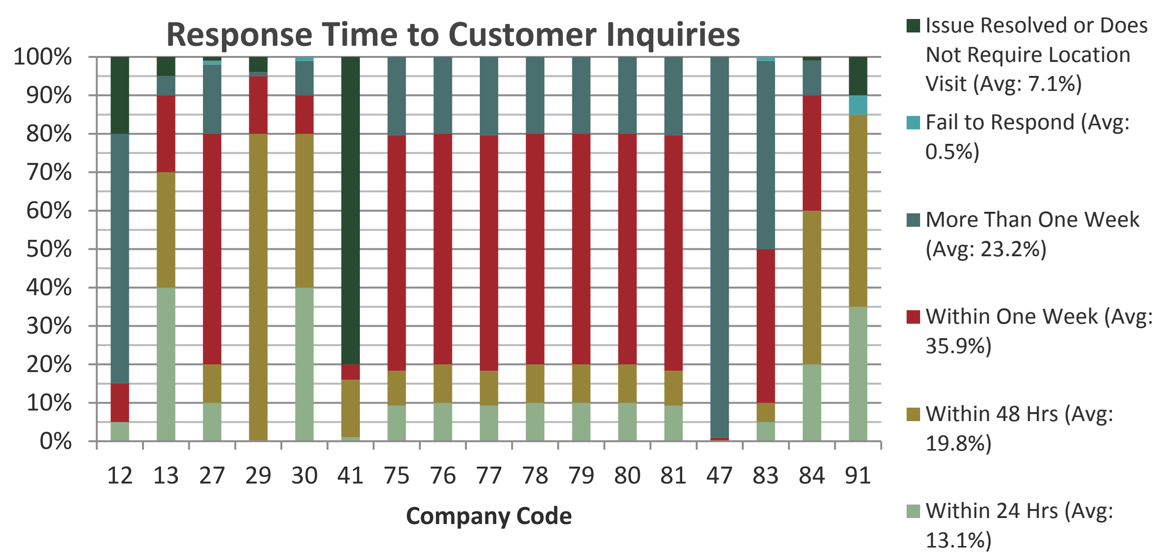


Figure 353: Response Time to Customer Inquiries

Comments on Response Time to UVM Related Customer Inquiries
Do not track in this manner.
Our goal is contact customers within 10 working days. We keep monthly aging records and find only .07% are 30 days old.
We don't keep records for this.
Estimated (2 responses)
We do not track anything with a zero response above. It is not like we do not have any.
No idea.
NOTE: 24/48 hrs. <10%
Globally the objective is 20 open days to go to the address/problem location and another 20 open days for the intervention to be done if the problem is real.

Figure 354: Comments on Response Time to UVM Related Customer Inquiries

CUSTOMER SERVICE REQUESTS

Person Responsible for Service Call Request Investigations

The objective of this question is to discover how customer requests are responded to by the utility.

Question #267: QUESTION: After information has been recorded from a telephone call, who goes to the location and evaluates the request?

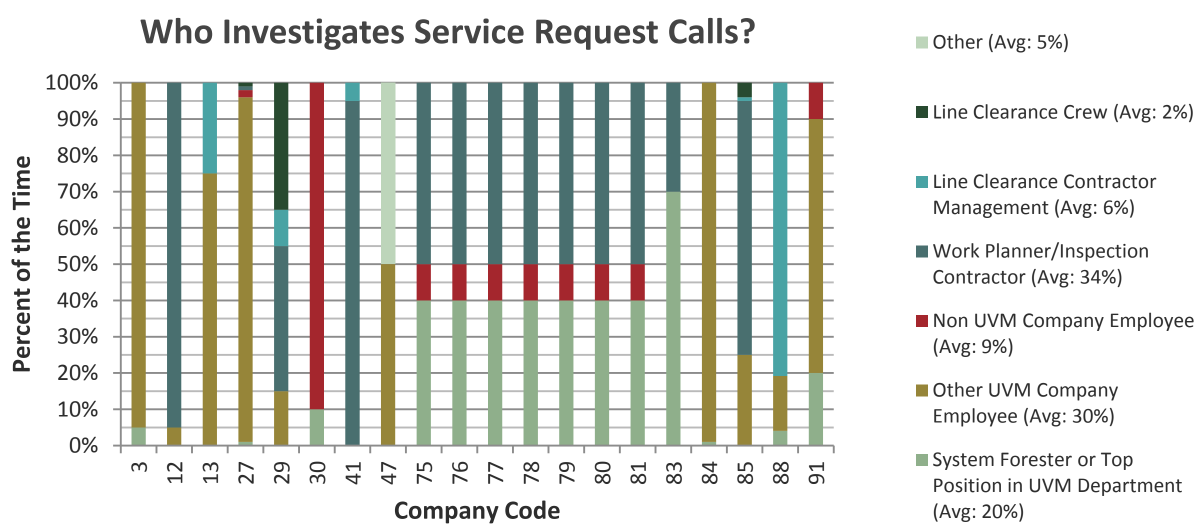


Figure 355: Who Investigates Service Request Calls?

Description of Other UVM Company Employees Who Investigates Service Request Calls
Forestry Technicians make the first field visit.
Forest technician who is a UVM company employee.

Figure 356: Description of Other UVM Company Employees Who Investigates Service Request Calls

Cost of Customer Service Requests

Question #268: Please enter the dollar amount and/or percent of total UVM expenditures that was spent on Customer/Property Owner requests.

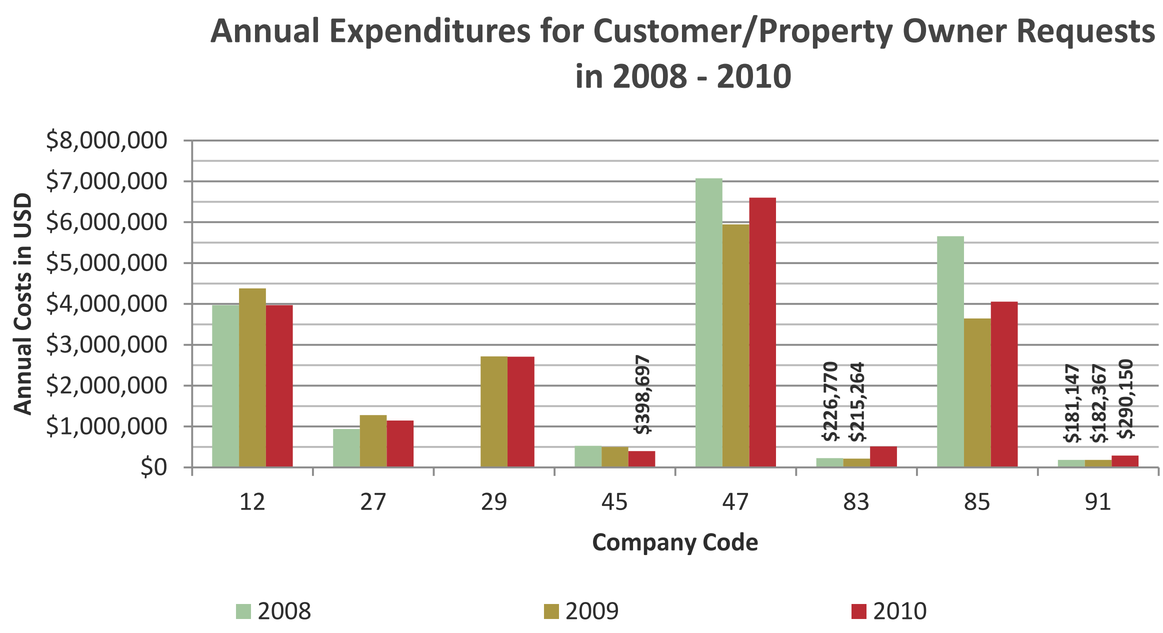


Figure 357: Annual Expenditures for Customer/Property Owner Requests in 2008 - 2010

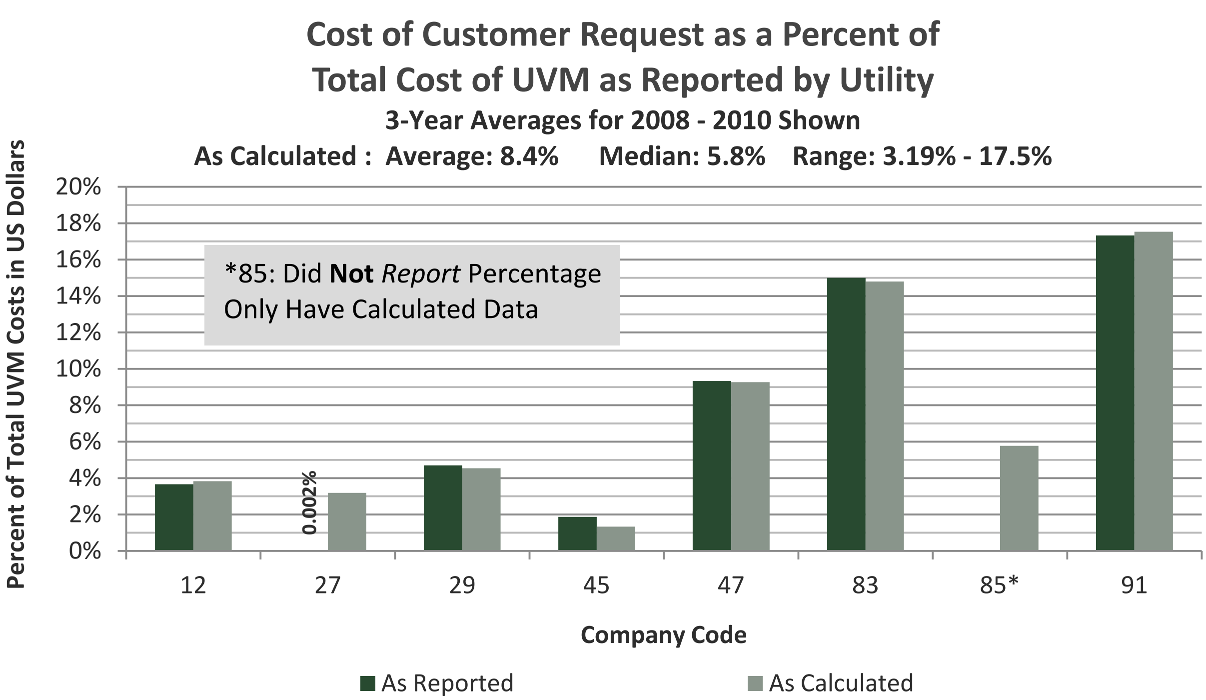


Figure 358: Cost of Customer Request as a Percent of Total Cost of UVM as Reported by Utility

RIGHT TO PERFORM UVM WORK

State Regulations of Customer Issues

Question #269:

Does your company follow any state regulations regarding customer notifications or other customer issues related to UVM?

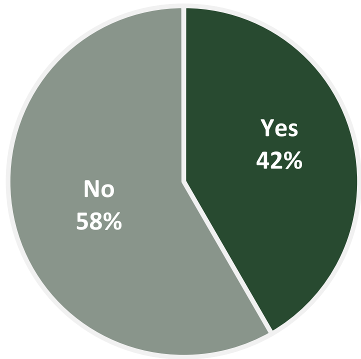


Figure 359: Do Companies Have State Regulations Regarding Customer Notifications and Customer UVM Issues?

Regulations that Apply to UVM Customer Issues
Service regulation #6
None
[State] Statue 163.3209 Part C. Before conducting routine scheduled vegetation maintenance within an established right of way, the utility must provide the official designated by the local government with a minimum of five (5) business days notice unless the maintenance is: 1. Required to restore electric service; or 2. Necessary to avoid an eminent vegetation-caused outage; or 3. Done at the request of the property owner adjacent to the right of way so long as the owner has approval of the local government, if needed.
Based off Commission
Pesticides Act requires property owner permission for herbicide application. Federal, Provincial and Municipal require notification for affected areas.

Figure 360: Comments on Regulations that Apply to UVM Customer Issues

Legal Right vs. Legal Obligation to Perform UVM

Percent of Companies with Legal Right vs. Legal Obligation to Perform UVM

Question #270:

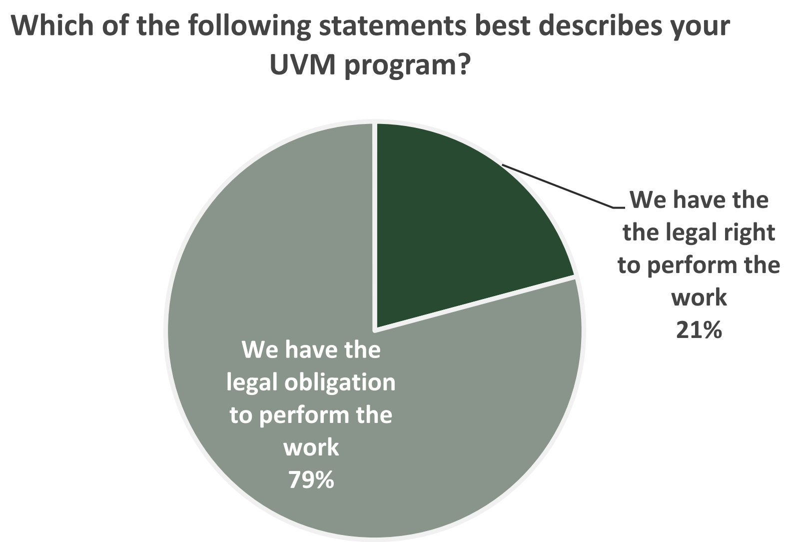


Figure 361: Legal Right vs. Legal Obligation to Perform UVM Work

Comments on Legal Right vs. Legal Obligation to Perform UVM Work
I would like to check both boxes in [this] answer.

Figure 362: Comments on Legal Right vs. Legal Obligation to Perform UVM Work

Conditions Regulating Utilities' Legal Right to Perform UVM

Participants were given several conditions and asked if these conditions were a part of their legal right to perform UVM work on customer's properties. The following graph has the condition that the most utilities included in their legal right to perform UVM at the bottom of the graph and decreasing as you move up the graph.

Question #271: True or false was entered for all categories.

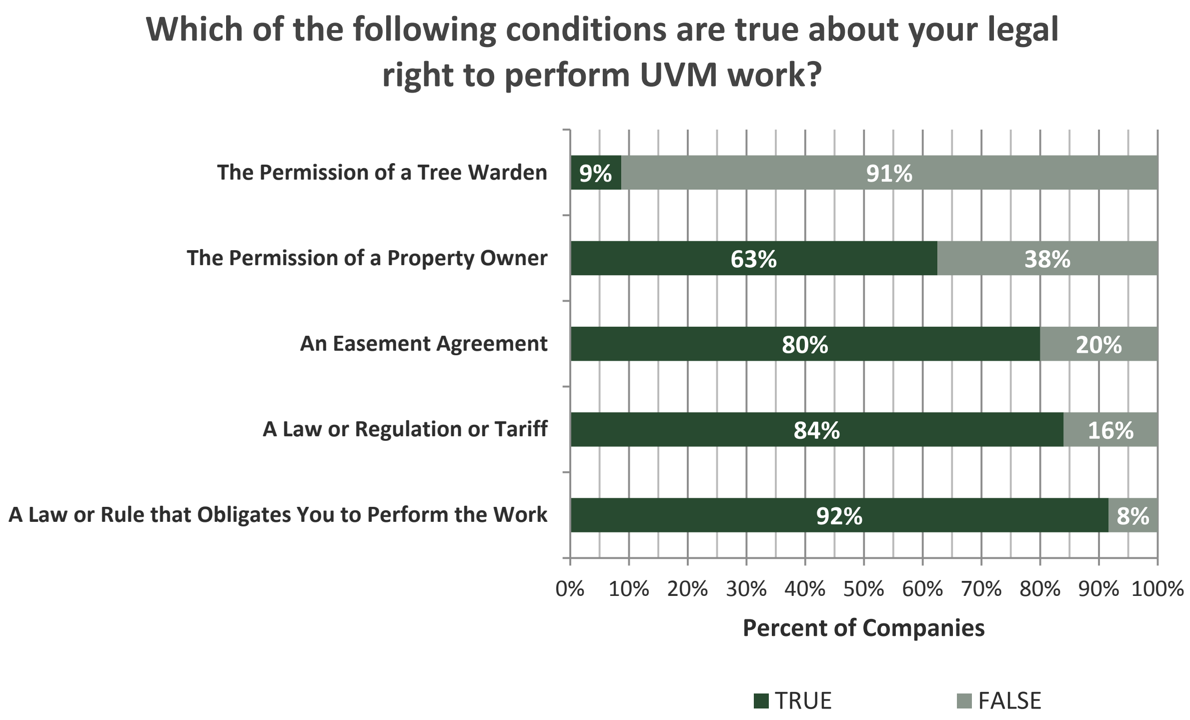


Figure 363: Conditions Regulating the Legal Right to Perform UVM Work

What Other Conditions Affect your Legal Right to Perform UVM?
Franchise agreement with city or county
Environmental, government, land agencies permits, forest service, bureau of land mgmt, tribal lands, and water shed.
Property owner permission for herbicide application.
State and Federal Agencies. Also as a Public Utility we bow to the wishes of the Politicians.
Very few easement agreements.
Court Case Judgments
UVM is a duty by a federal rule and our customer/owner has the right to claim, if we do not get his authorization first.

Figure 364: What other conditions affect your legal right to perform UVM? [Comment Table]

CUSTOMER SERVICE TRAINING

Question #272: Do you provide or require specific CUSTOMER SERVICE TRAINING for each of the following categories of UVM personnel? Check all that apply. Please describe your customer service training in the comment box.

Two graphs were made from this data. The first graph uses the data to understand how different employee types receive their customer service training. Only 12 companies answered this question, so it can be deduced from the top graph that *Notification/Workplanner Contract Employees* (Bottom of the chart) have the most extensive training. They are trained by more than one method (often more than two). The second graph looks at the same data to discover which training technique is the most predominant between companies. The most often used is at the bottom of the chart, decreasing in use as you move up.

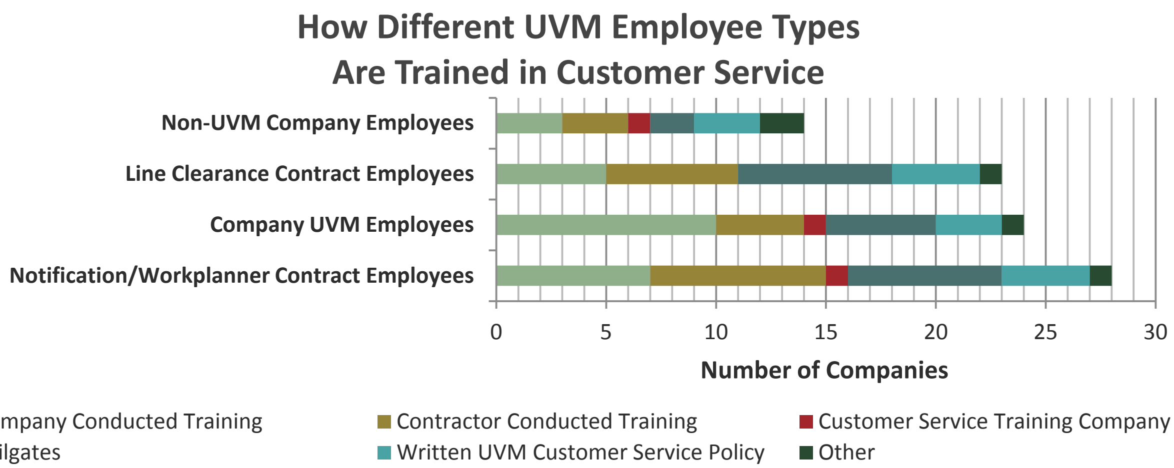


Figure 365: How Different UVM Employee Types Are Trained in Customer Service

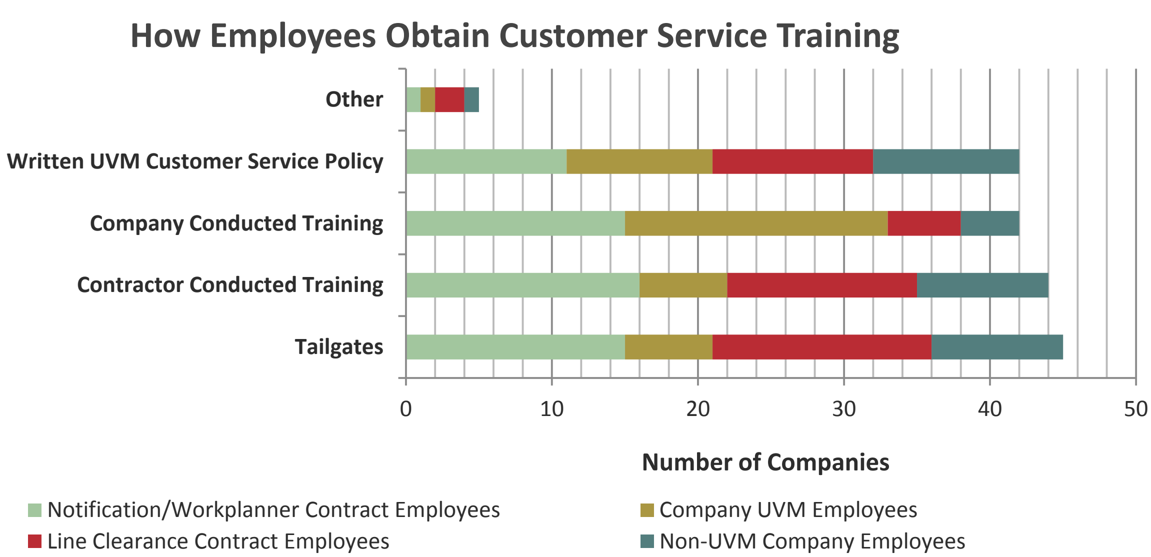


Figure 366: How Employees Obtain Customer Service Training

Descriptions of Customer Service Training Programs
Primarily tailgating and coaching/training on an on-going continual basis. Customer Service guidelines are also within the Trim Specifications and provided to all employees.
ISA, Utility Arborist Program, forester presentations, Treeline USA presentations
Public Relations programs such as "Dealing With Difficult Customers". Internal Conflict Resolution courses.
No customer service training is given to contractors. When they are used however, language in the contract specifies courteous customer service.
No specific customer service training.
Training is provided by supervisors, on the job training, manuals are handed out, online training, classroom safety and training seminars are held
It's been 15 years, we have not done such training.

Figure 367: Descriptions of Customer Service Training Programs [Comment Table]

PUBLIC EDUCATION PROGRAMS

Public Education Program Types Employed

Question #273: Do you have a public education program for UVM? From the following list please identify the programs that you currently employ to educate your customers and the general public on issues that relate to UVM. Check all that apply.

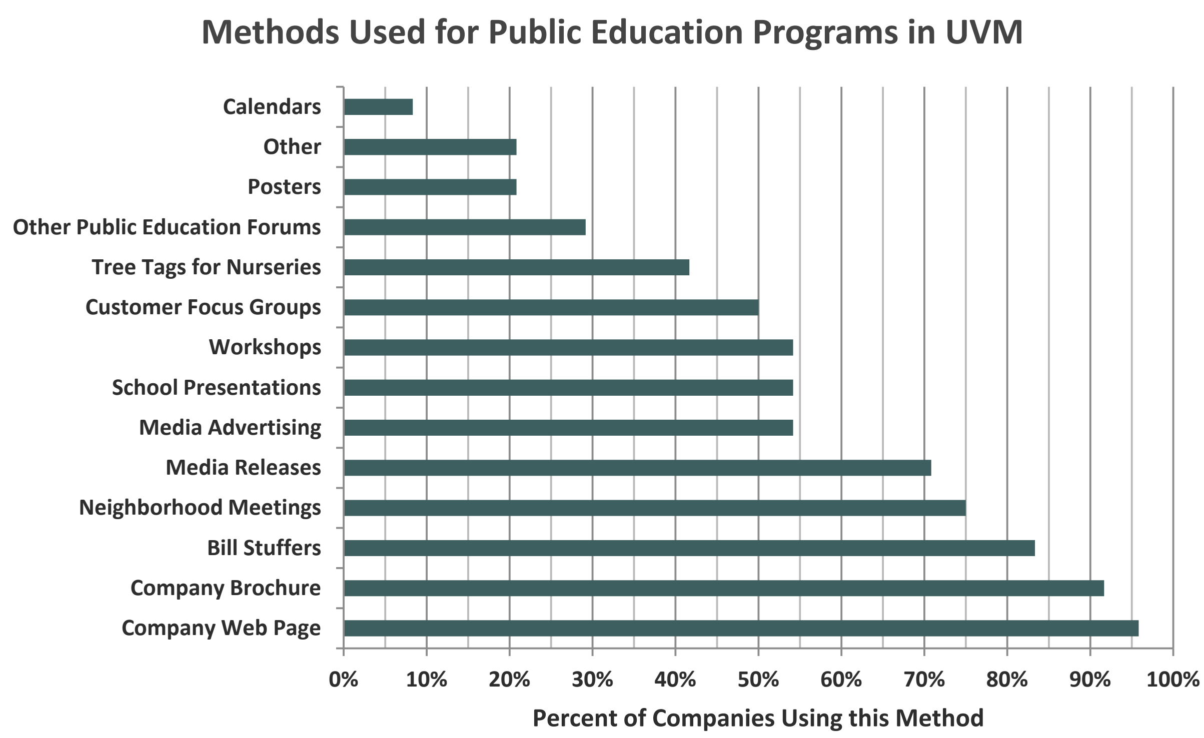


Figure 368: Methods Used for Public Education Programs in UVM

Other Public Education Forums
Know before you grow. Plan before you plant. [Other]
Booths at fairs, fund raisers, donations to firesafe councils, membership in community organizations, presentations at events and industry workshops... [Other]
Treeline USA presentations, City councils, scouts, youth, and special interest groups. [Other]
Farm and cottage shows and our right-tree-right-place program. [Other]
Our own newsletter. [Other]
Door cards. [Other]
Workshops with horticulture specialists. [Explanation of Workshops]

Figure 369: Other Public Education Forums [Comment Table]

Efficacy of Public Education Programs in Changing Customer Attitudes

Question #274: How successful are each of these educational approaches in changing customer attitudes towards UVM activities?

In the following graph, the most successful methodology would be the method with the lowest weighted average (top of the graph). The methods described as "Other" are in the comment table above ("Other Public Education Forums"). In fact, for the companies using methods described above, there was a belief that these were highly successful. Neighborhood meetings rated second most effective. It should be noted that none of the methods received an overall rating below *Somewhat Successful (2).*

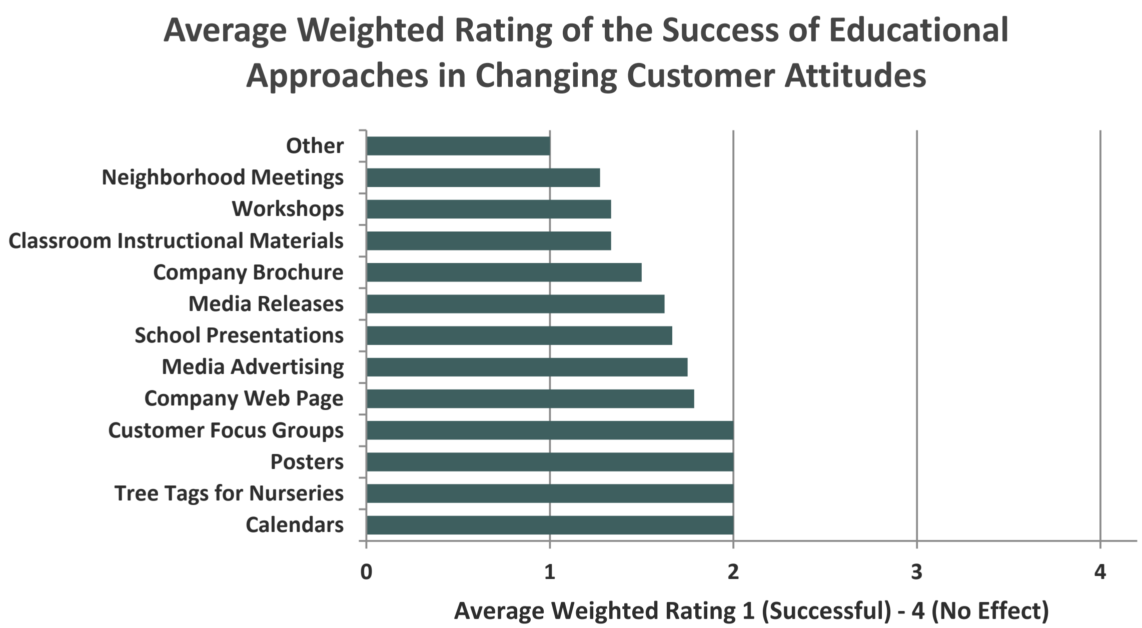


Figure 370: Average Weighted Rating of the Success of Educational Approaches in Changing Customer Attitudes

To get a better understanding of how companies rate the success of each methodology in changing customer attitudes towards UVM, the data is shown again in the following graph. One thing to note is there was not one company that rated any of the methods as having no effect. The only methods that were rated as having little effect were *Customer Focus Groups, School Presentations, Posters, Company Web Page, and Company Brochure.* It should also be noted that every method had at least one participant respond with *Do Not Know,* although some methods had several companies respond with this answer.

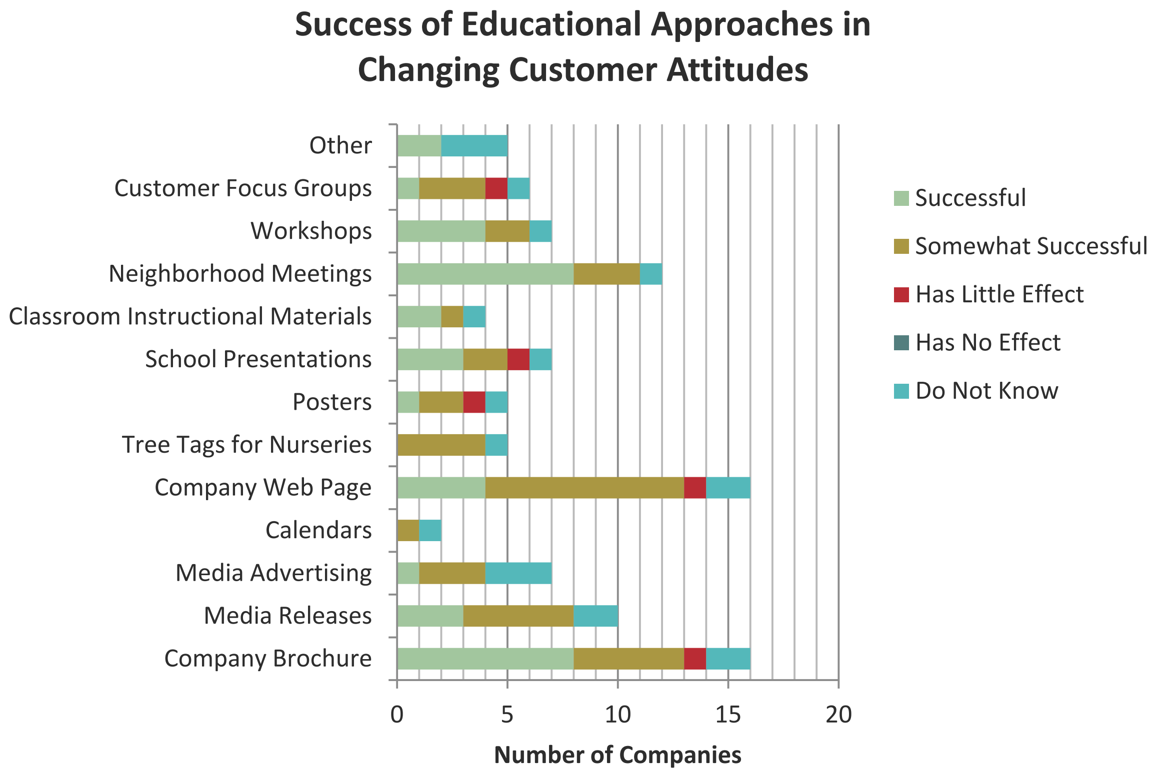


Figure 371: Success of Educational Approaches in Changing Customer Attitudes

Methods for Evaluating Public Education Programs for UVM

Question #275: Which of the following methods do you use to evaluate the effectiveness of your public and customer education programs? Check all that apply.

The responses to this question generated two graphs. The first graph shows how many companies have a way to evaluate the effectiveness of public education programs. The second graph only includes companies that do have methods for evaluating the effectiveness of customer education programs. The second graph displays the percent of companies that use each method of evaluation (some companies use more than one method).

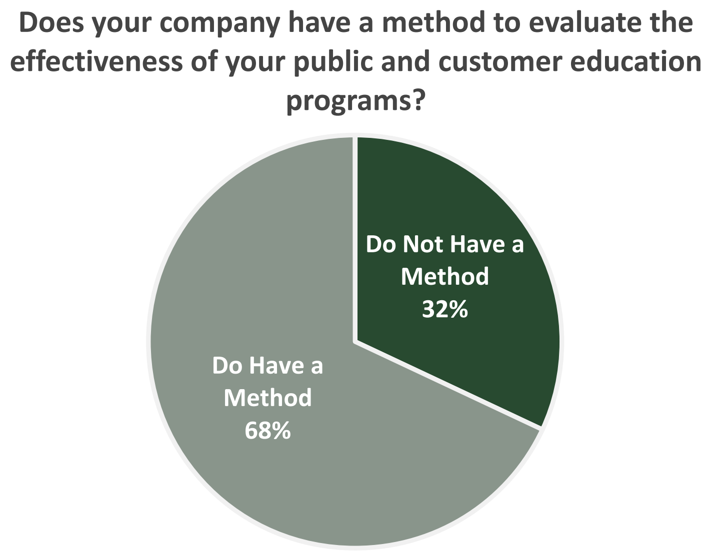


Figure 372: Percent of Companies that Have a Method for Evaluating Public Education Programs for UVM

The second graph only includes companies that have methods for evaluating public education programs. The responses in the following graph only pertain to 47% of the participants.

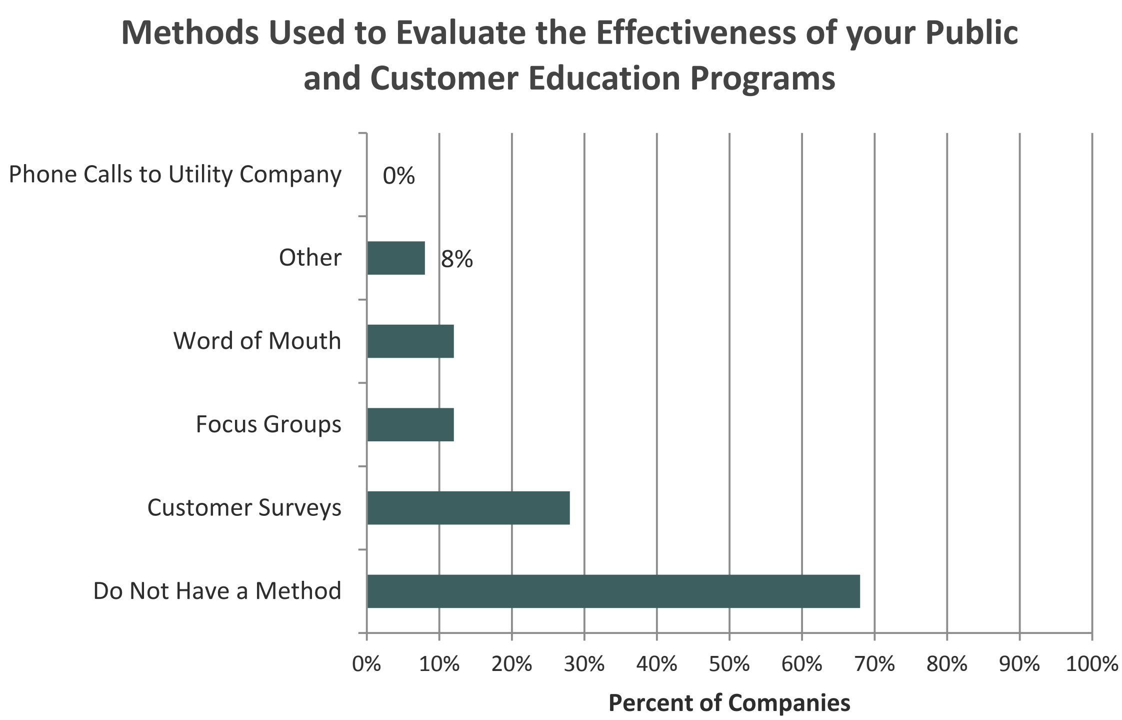


Figure 373: Methods Used to Evaluate the Effectiveness of your Public and Customer Education Programs

Other Evaluation Methods of Public Education Program Effectiveness
Feedback from presentations
Website touch points

Figure 374: Other Evaluation Methods of Public Education Program Effectiveness

Customer Service Surveys

Question #276: How do you conduct a customer service survey? Check all that apply.

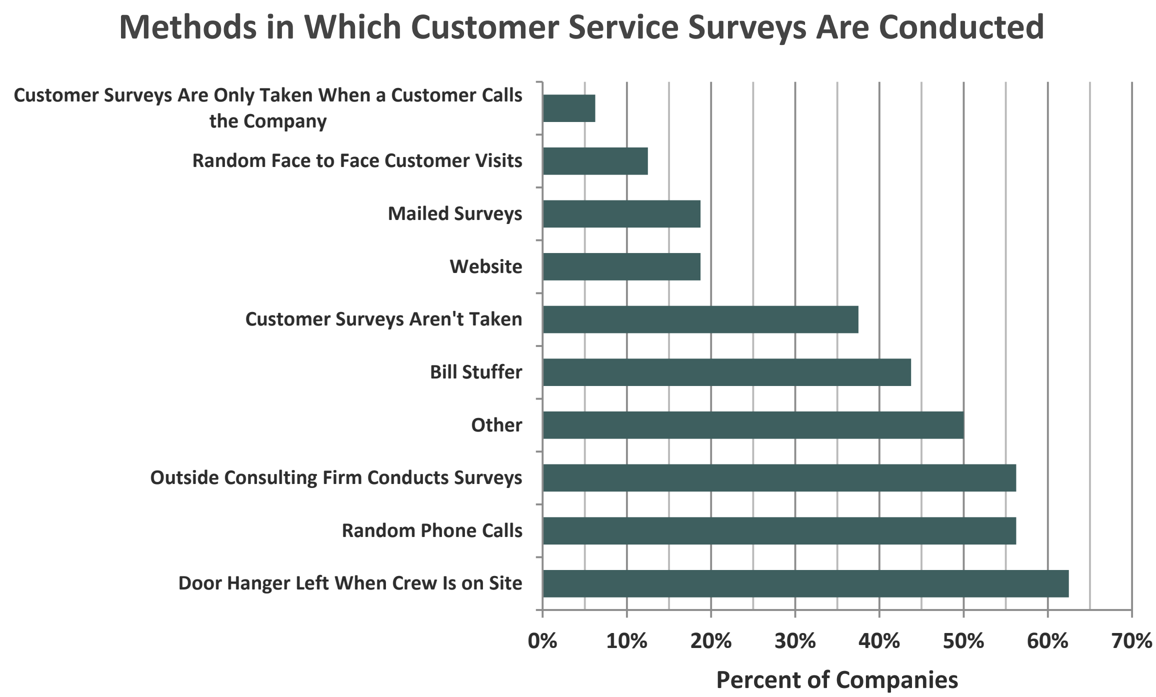


Figure 375: Methods in Which Customer Service Surveys Are Conducted

Comments on and 'Other' Methods Used for Conducting Customer Service Surveys
Vegetation only
Website email, face to face (forester, auditor, crew supervisors or manager). crew work - survey cards
We don't conduct surveys
JD Powers via internet surveys
The consulting firm calls after a job is completed. The survey is restricted to the work request that was routed through customer service.

Figure 376: Comments on and 'Other' Methods Used for Conducting Customer Service Surveys

Question #277:

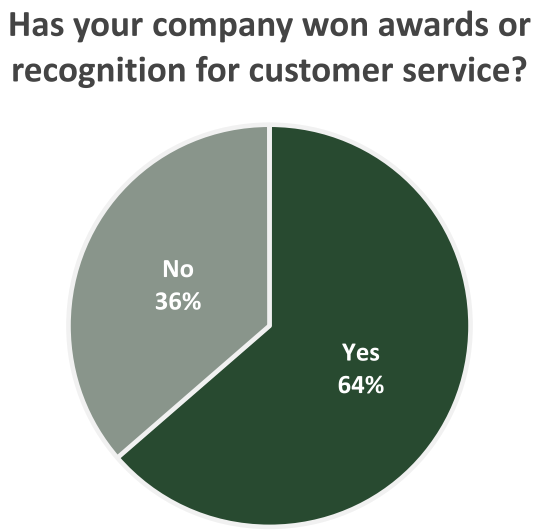


Figure 377: Company Customer Service Awards

Awards or Recognition for Customer Service
EEI 2011 National Accounts Customer Service Award
J.D. Power 2009-2010
Tree Line USA
Treeline USA for over 10 years and have received various other recognition awards but do not formally track.
Service One Award 8 years in a row
2007 Edison Electric Institute Award, 2007 Metering Award from Utility Planning, Network 2011 E-source review of North American Electric and Gas Company's, IVRs 2011 Top Utility "Usability for company's automated phone service", IVR Doctor's IVR/AVR Energy Utility Benchmark Report
Not for UVM though.

Figure 378: Awards or Recognition for Customer Service

GLOSSARY OF TERMS

AGGREGATE UNITS: Units based on larger groupings of trees or brush, such as partial spans, spans or miles/kilometers.

AUDITOR: Provides quality assurance and quality control services.

CAIDI: Customer Average Interruption Duration Index

CIRCUIT MILES: All miles of line. This includes multiple circuits on the same poles, as well as underground and overhead.

CREW LEADER: A qualified line-clearance arborist responsible for managing a crew of arborists.

DISTRIBUTION VOLTAGES: 1kV to 59kV

EMERGENCY STORM RESPONSE: This pertains to around the clock response to emergency conditions and includes additional forestry crews brought in for storm assistance.

FEEDER LINES: A primary line that distributes from a substation to the surrounding area. Feeder lines connect to primary voltage taps.

FISCAL YEARS: Fiscal years that end before June 29th should be listed as the preceding year. For example if the fiscal year ends on March 31, 2010, then include that fiscal year as 2009.

FORESTER: Performs a variety of duties necessary for managing the implementation of a UVM program.

GENERAL FOREPERSON: Supervises the management of several tree crews.

HAZARD OR RISK TREE: Trees are hazardous when the failure of one or more of their parts could result in property damage, personal injury and/or impacts to electrical lines.

INDIVIDUAL UNITS: Units based on individual trees OR small groupings of brush, under a quarter of a span or measured in square feet/square meters.

IN-GROWTH: the number of trees that periodically grow into the smallest inventoried diameter class of defined trees.

MAJOR EVENT (IEEE 1336-2003): Major Event represents those events of such a reliability magnitude that a crisis mode of operation is required to adequately respond. A T-med is mathematically derived to separate major events from non-major event. IEEE 1336-2003 major events are a standardized approach to defining STORM EVENTS.

NEW CONSTRUCTION: This pertains to any vegetation management work done to clear for the construction of new distribution lines.

NON-MAJOR EVENT (IEEE 1336-2003): Non-Major represents the reliability impact of those events that a company has built the system to withstand and staffed to respond to in a manner that does not require a crisis mode of operation (day-to-day operation). All outages that are not included in major event(storm) outages.

NOTIFIER/PERMITTER: Provides customer contact services.

OPEN WIRE SECONDARY EXTENSIONS: Separated three or two wire secondary voltage (<1kV) lines that extend beyond the range of primary voltage. This includes only pole to pole spans of secondary that do not also have primary voltage above.

POLE/SPAN MILES: Miles from first to last pole. There could be more than one circuit on the pole.

PRIMARY TAPS: Primary lines that are often single phase and run from the feeder line to transformers, secondaries and service lines serving homes and businesses.

QUALIFIED LINE CLEARING ARBORIST TRAINEE: An individual undergoing line clearance training under the direct supervision of a qualified line-clearance arborist. In the course of such training, the trainee becomes familiar with the equipment and hazards in line clearance and demonstrates ability in the performance of the special techniques involved.

QUALIFIED LINE CLEARING ARBORIST: An individual who, through related training and on-the-job experience, is familiar with the equipment and hazards in line clearance and has demonstrated the ability to perform the special techniques involved.

REACTIVE OR UNPLANNED WORK: This pertains to all unplanned UVM activities and includes such items as off-cycle requests, reliability work, and outbreaks of tree mortality caused by insects, disease, winter kill, drought etc.

ROUTINE MAINTENANCE: This pertains to any UVM that is planned into the budget and performed on a regular basis to keep the distribution lines clear of vegetation.

RURAL: Approximately 5-25 customers per circuit mile or 3-15 per km.

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SECONDARY TRIPLEX EXTENSIONS: Insulated and spun secondary voltage (<1kv) lines that extend beyond the range of primary voltage lines. This includes only pole to pole spans of secondary that do not also have primary voltage above.

SUB-TRANSMISSION VOLTAGES: 60kV to 199kV

SUBURBAN: Approximately 25-50 customers per circuit mile or 15-30 per km.

TRANSMISSION VOLTAGES: 200kV and above

TREE TREATED: ‘Treated’ is defined as the combination of trees pruned and removed. Number of Trees Treated = Number of Trees Removed + Number of Trees Pruned

URBAN: More than 50 customers per circuit mile or 30 per km.

UVM DIRECTOR: The person at your utility who is directly responsible for or has the most control over the distribution vegetation management program.

WORK PLANNER/INSPECTOR: Provides pre-inspection and field planning services. This position may include customer notification, scheduling, work prescriptions and audit services.

WORKLOAD INVENTORY: The number of trees worked or managed during a complete cycle.

OEB Staff Interrogatory # 39

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 4, 11-12, 40 - Construction Cost Index

PSE states on pp. 35-36 of its TFP Report that:

> *"In updating the Ontario industry TFP to 2015, PSE was unable to use the Electric Utility Construction Price Index (EUCPI), because it has been suspended after the 2014 data release. We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015. For the 2013, 2014, and 2015 plant additions, we use the capital expenditures found in the OEB Yearbooks. All other procedures remained the same relative to EB-2010-0379. For more information on the methodology, procedures, and 2002 to 2012 results please see the November 2013 report by PEG (Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board)."*

Interrogatory:

a) If PSE believes that the capital quantity growth of HON is more accurately measured using an alternative construction cost index, does it not also believe that the capital quantity growth of all Ontario distributors is more accurately measured using this alternative index? Please explain.

b) PSE criticizes the EUCPI for including financing costs. Since financing costs declined during the sample period, did this feature of the EUCPI tend to understate growth in construction costs and overstate growth in the quantity of plant additions? Please fully explain the response.

c) In footnote 3 at the bottom of page 4, PSE notes: "The first is using a different construction cost index in 2015. This is because the index used by PEG (the EUCPI) was suspended after its 2014 data release, making 2015 unavailable. For the years 2013 and 2014 we used the

EUCPI." On page 12, PSE states: "We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015."

i. Please provide the data used for the extension of the series.

ii. On what basis did PSE conclude that this would be a reasonable alternative to the EUCPI's publication suspension after 2014? Please recalculate the expanded Table 20 using PSE's alternative construction cost index.

Response:

a) Yes. When calculating the capital quantity growth of the industry and the input price inflation of the industry, both calculations should use a construction cost index that does not include financing costs. PSE believes the EUCPI is not an appropriate inflation measure of construction costs and will distort measured TFP trends and measured input price inflation. This holds for both an individual distributor's TFP and for measuring the entire TFP/input price inflation of the distribution industry.

PSE states on p.25 of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry:

For these reasons, PSE is far more comfortable using the Handy-Whitman indexes that measure total power distribution construction costs in the northeast U.S. In the U.S.-based TFP work, PEG regularly uses these same indexes. They do not include financing costs and are specific to the electric distribution industry.

This discussion is not meant to imply the 4th Generation IR research undertaken by PEG produced an improper price cap escalation formula. In a price cap mechanism there are two components that depend on the construction cost index used. These are: (1) the TFP trend (used for the productivity factor), and (2) the industry input price differential to a macroeconomic price index (e.g., GDPIPI). If the index is modified for one component, then it should also be modified for the other component. In other words, if EUCPI/Handy-Whitman is used for one component, the same source should also be used for the other component. These will tend to have off-setting impacts, making the choice of the construction cost index somewhat irrelevant to the overall escalation formula used within the price cap index.

However, this is not an irrelevant choice when demonstrating an individual distributor's TFP trend. In this study application of demonstrating Hydro One's performance, the best index to use is the Handy-Whitman index.

b) Yes, that is PSE's understanding. Since financing costs declined during the period, using the EUCPI had the effect of understating construction cost inflation. This, in turn, had the effect of overstating the quantity of plant additions. This had the effect of reducing the measured TFP trend, since the TFP trend is the change in the output quantity index minus the change in the input quantity index. The trend in the quantity of plant additions plays a large part in the input quantity index trend. The measured industry input price inflation will also be reduced by using the EUCPI by the decline in financing costs. These impacts should be off-setting to a large extent.

c) The data and calculation for the extension of the EUCPI is shown in the working papers in the file "Ontario Update to 2015 of 4GIR TFP.xls". It can be seen in the worksheet "3. TFP Database updated to 2015", column L, row 15. This same calculation is used for all the distributors.

Table 20 already includes the extension of the EUCPI to 2015 using the Handy-Whitman index growth rate.

OEB Staff Interrogatory # 40

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 4 – Sample

PSE states on page 4 of its Benchmarking Report that:

> *"In an effort to produce a dataset that can adequately capture Hydro One's large size and rural characteristics, PSE used a sample consisting of 380 U.S. distributors."*

Interrogatory:

a) Please provide a list of the U.S. utilities in the sample data base, by each of the two groups: (1) U.S. IOUs serving more than 10,000 customers; and (2) RECs serving more than 10,000 customers.

b) Utilities serving a large region with numerous customers typically also serve major metropolitan areas. Rural utilities typically serve far fewer customers and smaller urbanized areas. Please confirm that few, if any, utilities in the U.S. sample satisfy both PSE's large size and rural service territory criteria.

c) In light of the answer to b), why were no Ontario LDCs included in the study?

d) Does Form 7, which provided most operating data for the regional electric cooperatives ("RECs") in the sample, have a uniform system of accounts that is analogous to that which has long been available for FERC Form 1?

e) What precautions were taken concerning mergers of RECs or transfers of assets between the transmission and distribution accounts?

f) Where did PSE obtain its Form-7 data on the operations of RECs for 2012-2015 if "Publicly available Form-7 data" ended in 2011?

g) Please test the robustness of your methodology by reporting econometric and benchmarking results from a model that excludes observations relying on RUS-7.

Response:

a)

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Adams Electric Cooperative, Inc.	Alabama Power Company
Aiken Electric Cooperative, Inc.	Alaska Electric Light & Power
Albemarle Electric Member Corp	Allete (Minnesota Power)
Alger Delta Cooperative Electric Association	Appalachian Power Company
Altamaha Electric Membership Corporation	Arizona Public Service Company
Amicalola Electric Member Corp	Atlantic City Electric Company
Appalachian Electric Cooperative	Avista Corporation
Arab Electric Cooperative Inc.	Baltimore Gas and Electric Company
Arkansas Valley Electric Cooperative	Black Hills Power
Baldwin County Electric Member Corp.	Central Hudson Gas & Electric Corporation
BARC Electric Cooperative Inc.	Central Maine Power Company
Bartlett Electric Cooperative Inc.	Chugach Electric Association, Inc.
BENCO Electric Cooperative	Cleco Power LLC
Benton Rural Electric Association	Cleveland Electric Illuminating Company
Berkeley Electric Cooperative Inc.	Commonwealth Edison Company
Big Sandy Rural Electric Cooperative Co	Connecticut Light and Power Company
Blue Grass Energy Coop Corp.	Consolidated Edison Company of New York
Blue Ridge Electric Cooperative Inc.	Consumers Energy Company
Blue Ridge Electric Membership Corporation	Duke Energy Carolinas, LLC
Blue Ridge Mountain E M C	Duke Energy Kentucky, Inc.
Bowie-Cass Electric Cooperative Inc.	Duke Energy Ohio, Inc.
Broad River Electric Cooperative, Inc.	Duquesne Light Company
Brunswick Electric Membership Corporation	El Paso Electric Company
Buckeye Rural Electric Cooperative, Inc.	Empire District Electric Company
Butler Rural Electric Cooperative, Inc.	Entergy Arkansas, Inc.
C & L Electric Cooperative Corp.	Entergy Mississippi, Inc.
Caddo Electric Cooperative Inc.	Florida Power & Light Company
Callaway Electric Cooperative	Georgia Power Company
Canadian Valley Electric Cooperative Inc.	Green Mountain Power Corporation
Caney Fork Electric Cooperative Inc.	Gulf Power Company
Canoochee Electric Member Corp.	Idaho Power Co.
Capital Electric Cooperative Inc.	Indiana Michigan Power Company
Carroll Electric Cooperative Corp.	Indianapolis Power & Light Company
Carroll Electric Cooperative, Inc.	Jersey Central Power & Light Company

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Carroll Electric Membership Corporation	Kansas City Power & Light Company
Carteret-Craven Electric Cooperative	Kentucky Power Company
Cass County Electric Cooperative Inc.	Kentucky Utilities Company
Central Alabama Electric Cooperative	Kingsport Power Company
Central Electric Cooperative Inc. - PA	Louisville Gas and Electric Company
Central Electric Member Corp.	Madison Gas and Electric Company
Central Electric Power Assn.	Metropolitan Edison Company
Central Florida Electric Cooperative, Inc.	MidAmerican Energy Company
Central Georgia Electric Membership Corporation	Mississippi Power Company
Central Missouri Electric Cooperative Inc.	Nevada Power Company
Central New Mexico Electric Cooperative Inc.	New York State Electric & Gas Corporation
Central Rural Electric Cooperative	Niagara Mohawk Power Corporation
Central Texas Electric Cooperative Inc.	Northern Indiana Public Service Company
Central Valley Electric Cooperative, Inc.	Northern States Power Company - MN
Central Virginia Electric Cooperative	Northern States Power Company - WI
Cherokee County Electric Cooperative Association	Ohio Edison Company
Cimarron Electric Cooperative	Ohio Power Company
Citizens Electric Corporation	Oklahoma Gas and Electric Company
Clark Energy Cooperative	Orange and Rockland Utilities, Inc.
Clarke-Washington E M C	Pacific Gas and Electric Company
Clay County Electric Cooperative Corp.	PECO Energy Company
Clearwater Power Company	Pennsylvania Electric Company
Cloverland Electric Cooperative	Pennsylvania Power Company
Coast Electric Power Association	Portland General Electric Company
Coastal Electric Member Corp	Potomac Edison Company
Colquitt Electric Membership Corp.	Potomac Electric Power Company
Community Electric Cooperative	PPL Electric Utilities Corporation
Co-Mo Electric Cooperative, Inc.	Public Service Company of Colorado
Continental Divide Electric Cooperative, Inc.	Public Service Company of New Hampshire
Cookson Hills Electric Cooperative Inc.	Public Service Company of Oklahoma
Coosa Valley Electric Cooperative Inc.	Public Service Electric and Gas Company
Cotton Electric Cooperative Inc.	Puget Sound Energy, Inc.
Covington Electric Cooperative, Inc.	San Diego Gas & Electric Co.
Coweta-Fayette El Member Corp	Sierra Pacific Power Company
Craighead Electric Cooperative Corp.	South Carolina Electric & Gas Co.
Crawford Electric Cooperative Inc. - MO	Southern California Edison Company
Crow Wing Cooperative Power & Light Co	Southern Indiana Gas and Electric Company
Cullman Electric Cooperative, Inc.	Southwestern Electric Power Company
Cumberland Elec Member Corp	Superior Water, Light and Power Company
Cumberland Valley Electric Inc	Tampa Electric Company

Rural Electric Cooperatives in PSE Sample

Deep East Texas Electric Cooperative Inc.
Delaware Electric Cooperative Inc.
Delta Montrose Electric Assn
Dixie Electric Membership Corporation
Dixie Electric Power Association
Dubois Rural Electric Cooperative Inc.
Duck River Electric Membership Corporation
Duke Energy Indiana, LLC
East Central Energy
East Central Okla Electric Cooperative Inc.
Eastern Iowa Light & Power Cooperative
Eastern Maine Electric Co-op
Edgecombe-Martin County E M C
Edisto Electric Cooperative Inc.
Empire Electric Association, Inc.
EnergyUnited Electric Member Corp
Excelsior Electric Membership Corporation
Fairfield Electric Cooperative Inc.
Farmers Rural Electric Cooperative Corp.
Fleming-Mason Energy Coop Inc
Flint Electric Membership Corp
Florence City of
Forked Deer Electric Cooperative Inc.
Four County Elec Member Corp
French Broad Electric Membership Corporation
Gibson Electric Membership Corporation
Glades Electric Cooperative, Inc.
Golden Valley Electric Association Inc.
Grady Electric Membership Corporation
Grand Valley Rural Power Lines Inc
Grayson Rural Electric Cooperative Corp.
Great Lakes Energy Cooperative
GreyStone Power Corporation
Guernsey-Muskingum Electric Cooperative, Inc.
Gunnison County Electric Association Inc
Habersham Electric Membership Corp
Halifax Electric Member Corp
Hamilton County Electric Cooperative Association
Hancock-Wood Electric Cooperative, Inc.
Harrison County Rural E M C

Investor-Owned Utilities in Sample

Toledo Edison Company
Tucson Electric Power Company
Union Electric Company
United Illuminating Company
Upper Peninsula Power Company
Virginia Electric and Power Company
West Penn Power Company
Westar Energy (KPL)
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Wisconsin Power and Light Company
Wisconsin Public Service Corporation

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Haywood Electric Member Corporation	
Heartland Rural Electric Cooperative	
High Plains Power, Inc.	
Highline Electric Association	
Holmes-Wayne Electric Cooperative, Inc.	
Holston Electric Cooperative Inc.	
Holy Cross Electric Assn, Inc	
Horry Electric Cooperative, Inc.	
Houston County Electric Cooperative Inc.	
Howell-Oregon Electric Cooperative, Inc.	
Illinois Rural Electric Cooperative	
Indian Electric Cooperative, Inc.	
Inter County Energy Cooperative Corp	
Intercounty Electric Cooperative Association	
Irwin County Elec Member Corp	
Jackson County Rural Electric Membership Corporation	
Jackson Electric Member Corp	
Jackson Energy Cooperative Corp.	
Jackson Purchase Energy Corporation	
Jasper-Newton Electric Cooperative, Inc.	
Jefferson Electric Member Corp	
Jemez Mountains Electric Cooperative Inc.	
Johnson County Rural Electric Membership Corporation	
Kankakee Valley Rural E M C	
Karnes Electric Cooperative Inc.	
Kenergy Corporation	
Kit Carson Electric Cooperative Inc.	
Kootenai Electric Cooperative Inc.	
La Plata Electric Assn Inc	
Lake Country Power	
Lamb County Electric Cooperative Inc.	
Laurens Electric Cooperative, Inc.	
Lea County Electric Cooperative, Inc.	
Licking Valley Rural E C C	
Little Ocmulgee El Member Corp	
Little River Electric Cooperative Inc.	
Lorain-Medina Rural Electric Cooperative, Inc.	
Lumbee River Electric Membership Corp.	
Lynches River Electric Cooperative Inc.	
Macon Electric Cooperative	

Rural Electric Cooperatives in PSE Sample	Investor-Owned Utilities in Sample
Magnolia Electric Power Assn	
Maquoketa Valley Rural Electric Cooperative	
Meade County Rural E C C	
Mecklenburg Electric Cooperative Inc.	
Medina Electric Cooperative, Inc.	
Menard Electric Cooperative	
Meriwether Lewis Electric Cooperative	
Mid-Carolina Electric Cooperative, Inc.	
Middle Tennessee Electric Membership Corporation	
Midwest Electric, Inc.	
Midwest Energy Cooperative	
Midwest Energy, Inc.	
Mille Lacs Energy Cooperative	
Minnesota Valley Electric Cooperative	
Missoula Electric Cooperative Inc.	
Mohave Electric Cooperative Inc.	
Monroe County Elec Power Assn	
Mora-San Miguel Electric Cooperative Inc.	
Mountain Electric Cooperative	
Mountain Parks Electric, Inc	
Mountain View Electric Association, Inc.	
Navarro County Electric Cooperative Inc.	
Navopache Electric Cooperative Inc.	
Newberry Electric Cooperative Inc.	
New-Mac Electric Cooperative Inc.	
Nodak Rural Electric Cooperative Inc.	
Nolin Rural Electric Cooperative Corp.	
North Arkansas Electric Cooperative, Inc.	
Northern Neck Electric Cooperative Inc.	
Northern Plains Electric Cooperative	
Northern Virginia Electric Cooperative	
Northwestern Electric Cooperative Inc.	
Ocmulgee Electric Member Corp	
Okefenoke Rural Electric Member Corporation	
Orcas Power & Light Cooperative	
Osage Valley Electric Cooperative Association	
Otero County Electric Cooperative Inc.	
Owen County Rural Electric Cooperative Corp.	
Ozark Border Electric Cooperative	
Ozark Electric Cooperative Inc.	

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Panola-Harrison Electric Cooperative Inc.	
Pea River Electric Cooperative	
Peace River Electric Cooperative, Inc.	
Pee Dee Electric Cooperative Inc.	
Pee Dee Electric Member Corp	
Pennyrile Rural Electric Cooperative Co	
Petit Jean Electric Cooperative Corp.	
Pickwick Electric Cooperative	
Piedmont Electric Member Corporation	
Pioneer Electric Cooperative, Inc.	
Planters Electric Member Corp	
Plateau Electric Cooperative	
Pointe Coupee Elec Member Corp	
Poudre Valley R E A Inc	
Powder River Energy Corp	
Powell Valley Electric Cooperative	
Prince George Electric Cooperative	
Randolph Electric Membership Corporation	
Rappahannock Electric Cooperative	
Rayle Electric Membership Corp	
REA Energy Cooperative, Inc.	
Red River Valley Rural Elec Assn	
Rio Grande Electric Cooperative Inc.	
Rolling Hills Electric Cooperative	
Runestone Electric Assn	
Rusk County Electric Cooperative, Inc.	
Rutherford Electric Membership Corp.	
Sac-Osage Electric Cooperative Inc.	
Salt River Electric Coop Corp.	
San Isabel Electric Assn, Inc	
San Miguel Power Assn, Inc	
Sand Mountain Electric Cooperative	
Sangre De Cristo Elec Assn Inc	
Santee Electric Cooperative, Inc.	
Satilla Rural Elec Member Corp	
Sawnee Electric Member Corp	
Sequachee Valley Electric Cooperative	
Shelby Rural Electric Cooperative Corp.	
Shenandoah Valley Electric Cooperative	
Singing River Electric Power Association	

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Sioux Valley Southwestern Electric Cooperative	
Socorro Electric Cooperative, Inc.	
South Alabama Electric Cooperative Inc.	
South Central Ark Electric Cooperative Inc.	
South Central Power Company	
South Kentucky Rural Energy Cooperative Corporation	
South Louisiana Electric Cooperative Association	
South River Elec Member Corp	
Southeast Colorado Power Association	
Southeastern Indiana Rural Electric Membership Corporation	
Southern Maryland Electric Cooperative, Inc.	
Southern Pine Electric Cooperative Inc.	
Southern Pine Electric Power Association	
Southside Electric Cooperative Inc.	
Southwest Arkansas E C C	
Southwest Louisiana Electric Membership Corporation	
Southwest Mississippi E P A	
Southwestern Electric Cooperative, Inc. - IL	
Stearns Cooperative Electric Association	
Sumter Electric Cooperative Inc.	
Sumter Electric Member Corp	
Surry-Yadkin Elec Member Corp	
Suwannee Valley Electric Cooperative Inc.	
Tallahatchie Valley Electric Power Assoc	
Taylor County Rural E C C	
Tennessee Valley Electric Cooperative	
Three Notch Elec Member Corp	
Three Rivers Electric Cooperative	
Thumb Electric Cooperative	
Tideland Electric Member Corp	
Tipmont Rural Electric Member Corporation	
Tishomingo County Electric Power Association	
Trico Electric Cooperative Inc.	
Tri-County Electric Cooperative - MN	
Tri-State Electric Member Corp	
Umatilla Electric Cooperative Association	
Union Electric Membership Corp	
United Electric Cooperative Services Inc - TX	
Upper Cumberland E M C	
Utilities Dist-Western IN REMC	

Rural Electric Cooperatives in PSE Sample	**Investor-Owned Utilities in Sample**
Verdigris Valley Electric Cooperative Inc.	
Verendrye Electric Cooperative Inc.	
Vernon Electric Cooperative	
Warren Rural Electric Co-op Corporation	
Washington Elec Member Corp	
Webster Electric Cooperative	
West Florida Electric Cooperative Association, Inc.	
West Kentucky Rural E C C	
West River Electric Assn Inc	
Wheeling Power Company	
White River Valley Electric Cooperative Inc.	
Wild Rice Electric Cooperative Inc.	
Wiregrass Electric Cooperative, Inc.	
Withlacoochee River Electric Cooperative, Inc	
Wood County Electric Cooperative Inc.	
Woodruff Electric Cooperative Corp.	
Wright-Hennepin Cooperative Electric Association	
Yampa Valley Electric Association, Inc.	
Yellowstone Valley Electric Cooperative Inc.	
York Electric Cooperative, Inc.	

b) Confirmed. This is one of the key advantages of the econometric benchmarking method over peer group analysis. An econometric model can estimate the impacts of these and other characteristics and incorporate them into the benchmark. An accurate peer group analysis for Hydro One’s distribution system would not be possible.

c) Ontario distributors do not generally have either characteristic in question (large size or rural), let alone both. No Ontario distributor in the sample is the size of Hydro One, and most Ontario distributors are serving municipalities rather than vast rural areas. There are two primary reasons for PSE not including the Ontario distributors in the sample. The first and foremost reason is that some of the GIS-related variables are not available for all distributors in the Ontario sample. Important variables such as percent forestation, square kilometres served, and percent of territory that is “artificial surface” could not be included, and this would limit the model’s ability to accurately incorporate these cost drivers into the model. The second reason is the experience of Toronto Hydro’s last custom IR application (EB-2014-0116), when PSE did provide econometric benchmarking evidence that included two models and datasets: 1) a combined Ontario and U.S. dataset and 2) a U.S. only dataset. PEG conducted research on behalf of the OEB staff in that proceeding and conducted benchmarking research using the U.S. only dataset. Much of the discussion centered around the U.S. only results for both consultants. It appeared that both consultants agreed the U.S. only dataset was the more appropriate one to use when benchmarking an Ontario outlier utility such as Toronto Hydro. Hydro One is also an extreme outlier.

d) Yes. Due to the length of the document, in lieu of a paper copy please see the following link for the Uniform System of Accounts used by RECs.
https://www.rd.usda.gov/files/UPA_Bulletin_1767B-1.pdf

e) PSE examined the data for implausible changes, which would indicate a merger or substantial transfer of assets. In the case of a merger, the issue would be that the reported capital would likely be too low for the newly formed utility, due to the fact that prior year plant additions and 2002 benchmark year net plant would only contain the capital for the pre-merged company. This would lower the total costs for the merged company, likely lowering the benchmark expectation for Hydro One. If there are merger issues within the sample of 380, this will tend to create a more challenging benchmark for Hydro One. Regarding the possible transfers of assets/plant, given the perpetual inventory method of calculating capital, a transfer of gross assets/plant in service from one function to another will not impact the capital cost measure. In the case of transmission and distribution transfers, most of the RECs are distribution-only utilities, and these would not have the ability to transfer assets to/from transmission.

f) The REC data ended in 2011; only the IOU data extended to 2015.

g) This exercise would not "test the robustness" of the methodology. Excluding over 75% of the sample and, specifically, excluding the portion of the sample that is rural and is included to enable accurate estimation for the extreme rural characteristics of Hydro One is not a test of robustness. However, if an IOU-only dataset is to be used then there must be included a variable to adjust for the extreme outlier status of Hydro One as it relates to density. We have re-run the same model with the IOU-only dataset but inserted a quadratic term on the density variable. This variable comes in highly statistically significant. PSE believes the "IOU plus REC" model is superior. However, the results for the IOU-only model (with the only change being an inserted quadratic variable on density to control for Hydro One's extreme density in an IOU-only model) show Hydro One being 18.7% above benchmark costs in 2022. These results are quite close to the IOU plus REC results and continue to indicate that Hydro One should be assigned a stretch factor of 0.45%.

Year	**IOU Plus REC (PSE Model)**	**IOU-only Model (with quadratic density)**
2014	29.3%	21.9%
2015	23.2%	16.7%
2016	21.6%	17.2%
2017	21.3%	16.5%
2018	21.4%	16.9%
2019	22.0%	17.6%
2020	22.4%	18.2%
2021	22.4%	18.3%
2022	22.7%	18.7%

OEB Staff Interrogatory # 41

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 12 - Cost Calculations
PSE states on page 12 of its Benchmarking Report that:

> *"We used Hydro One's distribution net plant in 2002. For the rest of the sample we calculated each utility's total net electric plant and then allocated the distribution portion by the percentage of gross distribution plant in total gross electric plant in 2002."*

Interrogatory:

a) Is the cost of general plant excluded from the study for any of the sampled utilities? If so, why? If so, please provide the data required to calculate a capital quantity index for Hydro One's general plant.

b) What precautions were taken concerning U.S. mergers and acquisitions and transfers of plant between transmission and distribution accounts?

c) How did PSE calculate OM&A expenses of Hydro One, U.S. investor-owned utilities ("IOUs"), and rural electric cooperatives ("RECs")?

d) How were administrative and general expenses handled?

e) Where do pension and benefit expenses appear in Form 7? Are these itemized?

Response:

a) No. An allocated portion of general plant is included.

b) See PSE's response to Exhibit I-10-Staff-40, part e).

c) Hydro One, the IOUs, and RECs all had the same calculation for OM&A expenses. The calculation can be found in the working papers (Exhibit I-08-Staff-023). The OM&A

expenses are the sum of the distribution expenses (including high voltage and smart meter expenses for Hydro One) plus the customer care accounts and an allocated amount of administrative and general (A&G) expenses. The allocation of A&G is based on the ratio of: (distribution plus customer care expenses) to (total expenses minus fuel/purchase related expenses, A&G expenses, and transmission by other expenses). Please see the working papers for the exact calculations.

d) Please see the response to part c).

e) The pension and benefit expenses are not itemized the Form 7.

OEB Staff Interrogatory # 42

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 7 - Benchmark Year Adjustment
PSE states that:

> *"We use 2002 as the benchmark year in the current study for all utilities"*.

Interrogatory:

a) What is the earliest practicable benchmark year for calculating a capital quantity index for the sampled RECs?

b) What is the earliest practicable benchmark year for the sampled U.S. IOUs?

c) Why was a 2002 benchmark year used for US companies as opposed to the earliest practicable year?

d) Does the use of a 2002 benchmark year when an earlier benchmark year is available reduce the accuracy of estimated capital costs for U.S. utilities?

e) Please test the robustness of the econometric and benchmarking results by re-estimating the model using the earliest practicable benchmark year for each sampled utility.

f) Does Hydro One have available data on plant in service and accumulated depreciation prior to 2002 which might allow the calculation of an earlier benchmark year? If so, please provide.

Response:

a) 1995.

b) 1988.

c) The first possible benchmark year for Hydro One is 2002. PSE wanted to be consistent in the capital calculations between Hydro One and the rest of the dataset. Having different calculations between the sampled utilities and Hydro One could introduce an unknown but avoidable bias in the results. Having a consistent benchmark year outweighs the benefits of beginning the benchmark year earlier, in PSE's opinion.

d) Yes, it likely does. However, PSE believes having consistent calculations between the studied utility and the sample outweighs this. Introducing a potential bias into the study by starting the capital calculations at different dates can and should be avoided.

e) This would not be a "test of robustness" in PSE's opinion. Possibly introducing a bias into the study, and then seeing if the results align is not a test of robustness. Even given that, PSE is unable to conduct this exercise, as we did not gather data prior to 2002 in the study, and the level of effort of gathering and processing historical data for 380 utilities (plus changing the calculations to account for a different benchmark year for different utilities within the sample) would require a large amount of effort.

f) Hydro One agrees with PSE that having a consistent benchmark year outweighs the benefits of beginning the benchmark year earlier. Introducing an earlier benchmark year would not be a test of robustness of the econometric and benchmarking results. The exercise of providing data prior to 2002, and potentially to the earliest practicable year of 1995, would require a large amount of effort and would not produce any results since PSE did not gather data prior to 2002.

OEB Staff Interrogatory # 43

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 8 - Right-Hand Side Variables

PSE states on page 8 of its Benchmarking Report that the output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Maximum peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

- Regional input prices,
- Percent electric customers (out of total gas and electric customers),
- Forestation of the service territory,
- Square kilometers of territory served per customer,
- Percent of territory designated as "artificial surface,"
- Percent customer service and information expenses in distribution OM&A,
- Extreme weather conditions, and
- A time trend variable.

Interrogatory:

a) Please explain fully how the peak demand data are defined in all three data sources (i.e. including Ontario). Since the REC demand data are from Form 7, how did PSE deal with the fact that RECs are permitted on that form to file either coincident or non-coincident peak demand data? Which approach was most common? Which RECs changed their approach to reporting demand data during the sample period? What adjustments were made to the raw demand data to create the "maximum peak demand" variables used in the modelling?

b) Please confirm that PSE's labor price indexes for sampled U.S. electric utilities are constructed from BLS salary and wage data. What indexes were used to escalate the U.S. labor price index?

c) Please provide a thorough explanation of PSE's calculation of a labor price index for Hydro One.

d) Please describe how the benchmarking study accounted for differences in company-provided benefits (e.g. health care and pensions) of the U.S. utilities and Hydro One.

e) Ref Page 10: "…To construct the overall OM&A input price, we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used by PEG in their benchmarking research."

   i. Please confirm that PEG used these O&M weights to construct an OM&A price index for a cost benchmarking model that was estimated using only Ontario data.
   ii. Were the 70/30 weights applied to the sampled US LDCs as well as to Hydro One? If so, why?
   iii. What is a typical share of labor cost in the O&M of US power distributors?

f) Ref Page 5: "The Ontario component uses the same GDP-PI in each year, but adjusted for the purchasing power parity ("PPP") index."

   i. Was the PPP adjustment for O&M expenses applied for one year or every year?
   ii. Why is the PPP preferred over the exchange rate in this application?
   iii. Does "GDP-PI" here refer to a US GDP-PI or a Canadian index? Please identify the specific index used.

g) The RS Means indices for which cities were used to levelize the capital price indexes for sampled utilities?

h) Please provide thorough explanations on how the forestation, customer density, and artificial surface variables were constructed. For example, how was the service territory of each company defined?

i) Please prepare a table that compares Hydro One's 2015 values for the cost model's RHS variables to the mean 2015 values for sampled RECs, IOUs, and the full US sample.

j) Please describe any steps to control for the differing amount of sub-transmission work done by sampled US distributors and HON.

k) Please describe the relative merits of attempting to control for the cost of conservation programs as opposed to removing the cost as was done in the Ontario benchmarking work.

l) Please describe any efforts to control for the cost impact of differing amounts of distribution system undergrounding among LDCs.

m) Please describe any efforts to control for differences in the distribution system age of sampled LDCs.

Response:

a) The system peaks were gathered from SNL's database for the RECs and IOUs. Hydro One's system peaks were gathered directly from the utility, with Norfolk peak data added. The Hydro One data is defined as the coincident system peak, with embedded distributors included in the peak demand value. As PSE states on page 9 of the Benchmarking Report, "the Hydro One distribution system network needs to be built to accommodate both its own system demands and those of the embedded distributors." To PSE's knowledge, SNL Energy does not indicate whether the REC peak demand reported for a given utility is coincident peak (CP) or non-coincident peak (NCP). A CP will necessarily always be equal to or less than a NCP. Since the Hydro One definition is a CP, with the small exception of Norfolk being added in, the value will be below what the company's NCP value would be. To the extent the sample contains some observations reporting NCPs, this would likely create a lower and more challenging benchmark for Hydro One. In PSE's experience with RECs, the CP and NCP demands will be relatively close. The reason is that most RECs will report CP demands based on their power supplier's coincident peak time. Most of the RECs are served by power suppliers that are relatively close geographically (most RECs actually have an ownership share in their power suppliers). Therefore, when the power supplier peaks the REC tends to be very near its own peak demand. PSE believes this will introduce a low error into the model, and to the extent there is an error, it will tend to make the Hydro One benchmark more challenging.

Observations missing peak demand data were excluded from the sample, but no other modifications were made to the reported data.

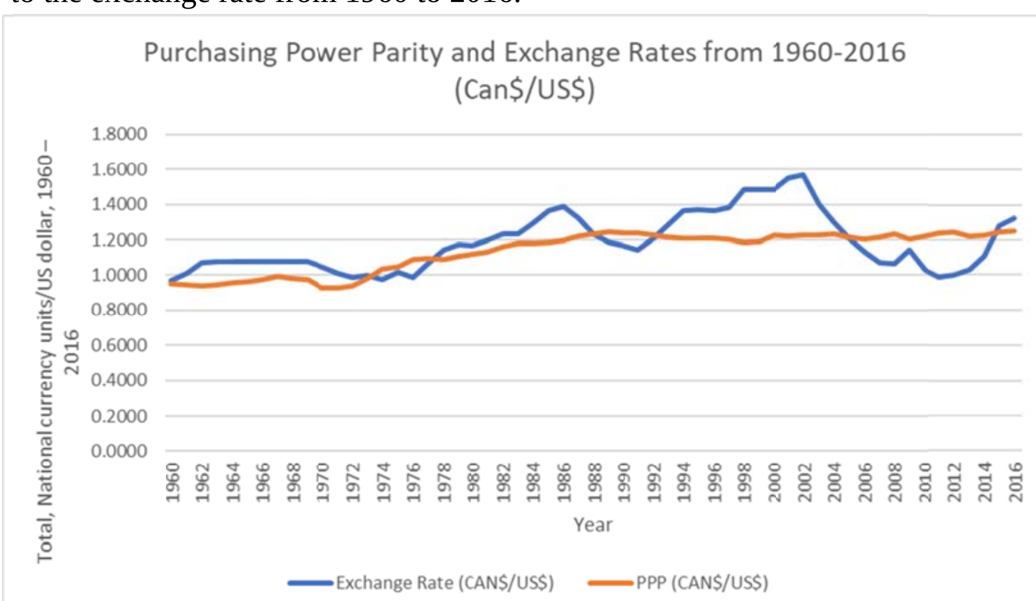
b) Confirmed. The escalation index used is the Employment Cost Index (ECI) for the Utility industry and includes total compensation from the BLS. The series Id is CIU2014400000000I.

c) PSE used the same ECI index mentioned in the answer to part b) to escalate Hydro One's labor price index.

d) All A&G expenses for the U.S. sample and Hydro One were included in the cost definition and allocated based on the distribution allocation. There was no adjustment made for differences in benefits. The REC data does not make an adjustment possible, since these expenses are not broken out.

e) PSE confirms that PEG used the O&M weights on an Ontario-only dataset. PSE applied the same weighting to Hydro One and the sampled utilities. This is done for consistency between Hydro One and the sample. Using each utility's specific salary information, if that were available, would be problematic, as outsourcing and other expense accounts also contain labour costs. Further, the REC data does not have salary and wage data available from SNL. PSE is of the opinion that the 4GIR method of fixing the labour/non-labour weights at 70/30 is an appropriate one. Given that the data for the RECs is to our knowledge unavailable, PSE cannot provide and answer to part iii.

f) The U.S. GDPPI index is used and adjusted every year by the Canadian PPP to put the price into Canadian dollars for Hydro One. The PPP is preferred over the exchange rate due to the stability of the PPP compared to the exchange rate. The graph below compares the Canadian PPP to the exchange rate from 1960 to 2016.



g) Please see the working papers in the file named "RS Means Mapping.xls" (Exhibit I-8-Staff-023).

h) Please see page 10 and 11 of the Benchmarking Report for details. The website link to the GIS layer for the land area types is here: http://due.esrin.esa.int/page_globcover.php
For the service territory maps, PSE purchased a GIS layer from Platts. The link to the product is provided here: https://www.platts.com/products/map-data-pro

i) The table below provides the right-hand side variables for the model. The question requests 2015, however the REC data only goes through 2011 and some IOU observations do not have 2015 data. We have constructed the table to show the 2015 Hydro One variable values and then averaged the most recent year available in the dataset for each utility. The last row shows the average "most recent year" for the IOUs, RECs, and for the full dataset.

Dataset Averages for Most Recent Year (except Hydro One = 2015)

Variables in the Model	Hydro One	IOUs	RECs	Full Dataset
Number of Customers	1,257,016	929,550	36,662	241,410
Maximum Peak Demand	7,189	5,451	216	1,416
Square KM per Customer	0.765	0.025	0.159	0.051
Percent Electric Customers	100.0%	89.1%	99.8%	97.4%
Percent Forestation	74.2%	59.5%	61.4%	61.0%
Percent Customer Service and Information	0.3%	22.4%	4.9%	8.9%
Extreme Weather	2,420	1,376	2,320	2,107
Percent of Territory that is Artificial Surface	0.1%	2.0%	0.1%	0.5%
Most Recent Year Average		2014.7	2010.9	2011.8

j) High voltage expenses for Hydro One have been added to the company.

k) The CDM costs are not included for Hydro One. However, the obstacle is that some U.S. utilities include CDM costs in the customer service and information expense category. Since these costs are not explicitly broken out on the FERC Form 1 or RUS Form 7 data it is impossible to remove the CDM costs for the US utilities. With no correction, this would create an unfair advantage to Hydro One and likely raise their benchmark costs. PSE has noticed that PEG has used a similar "percent customer service and information" variable in their other benchmarking research to adjust for the differences in CDM reporting amongst utilities.

l) This is not possible, as much of the line mile data for underground and overhead lines for the U.S. sample is either unavailable or not trustworthy. PSE does not believe the UDI Directory data provides robust enough data for length of line measurements, nor does it provide an underground vs. overhead breakdown. An underground plant in service variable is not possible, as the data are not available for the RECs.

m) No efforts to control for system age were conducted.

OEB Staff Interrogatory # 44

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 10 – PSE Total Cost Benchmarking Study

PSE discusses one of the variables in the total cost benchmarking study as Square Kilometers per Customer:

> *"The square kilometers per customer variable is calculated using GIS coordinates of each utility's service area provided to PSE by Platts. The variable equals the total square kilometers of the area of the distributors service territory divided by the number of retail customers served. The customer variable is the same as the output variable that enters the model. We would expect distributors that have to cover more service territory per customer to have higher costs."*

While PSE's expectation is reasonable among firms that are more or less homogeneous in many respects, such as operating in similar geographical regions of the continent, this may not hold across North America. In western Canada and the U.S., state areas are typically larger. There are also more areas in some provinces and states where there may be no electrification (e.g. federal or state/provincial parkland or reserves). Hydro One has some of this in its territory in Ontario (e.g., provincial parks such as Algonquin, Chapleau Crown Game Reserve, etc.). Electrical service may be restricted along transportation corridors (generally roads and highways, railways), along which nearly all residences and businesses will be located. Trivially, there are no costs for unserved territory.

For this reason, customers per kilometer of line (circuit km. of line) is often preferred as a better measure of density than is customers per square kilometer. This may be particularly true given the differences in utilities' service territories across the North American continent.

Interrogatory:

a) Did PSE consider a measure of density per kilometer of line? If so, why was it rejected? If not, why not?

b) Given observed differences in utilities' service territories across North America, please provide PSE's view on whether this measure would introduce any error or bias in its benchmarking results.

Response:

a) PSE agrees that density per kilometer of line could be considered as a variable, if robust data existed. However, in PSE's experience, there is not a trustworthy source of this data for the U.S. utilities. The issue arises in the counting of primary and secondary lines. Some utilities report primary-only, some report primary plus secondary. The differences can be quite large. The most comprehensive data source for distribution line lengths that PSE is aware for North American utilities is the Platts UDI Directory of Electric Power Producers and Distributors. In the working papers (Exhibit I-8-Staff-023), we include this data for parties to investigate. From year to year for many utilities, the values have implausible movements either up or down. Introducing this data is problematic and would likely introduce a large bias. If the studied utility reports primary plus secondary line lengths, the study will be biased in favor of them. Conversely, if the studied utility reports primary only, then the study will be biased against them. These biases could be large, and so in PSE's opinion this variable should not be used at this time.

b) The measure PSE used for density is based on density per service territory. Given the sample has several utilities that do serve vast open areas, such as in the western U.S., the model estimation will estimate the best model based on that data. A quadratic term for the density per square kilometer variable could be considered to account for the differences cited in the interrogatory. If we insert that variable into the model, the benchmarking result for Hydro One improves by about 6% in 2022: from 22.7% over total cost to 16.4% over total cost.

OEB Staff Interrogatory # 45

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-02 Page: 11, 15 and 16 – PSE Total Cost Benchmarking Study
On pages 15-16, PSE states:

> *"As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory, and is largely outside the control of a firm's managers. On the other hand, the number of employees hired are within management's control, and thus cannot serve as an independent variable."*

One of the "independent" explanatory variables included by PSE in its analysis, is percentage of customer service and information expenses, which is defined on page 11 as:

> *"The percentage of customer service and information expenses is calculated by taking customer service and information expenses and dividing by the total OM&A. Since some U.S. distributors include their conservation demand management expenses within the customer service and information expense category, this variable accounts for those cases. We would expect a higher percentage of customer service and information expenses to be associated with higher total costs."*

Interrogatory:

a) How many U.S. distributors include conservation demand management costs in the customer service and information expense category?

b) Are all such programs mandated by government or regulatory policy, or how much discretion does the utility have with respect to both the conservation demand management targets, achieving those targets and their control?

c) How are Hydro One's costs for achieving the CDM targets established by the IESO (and formerly the OPA) recorded?

d) This variable is dependent on both the firm's overall level of OM&A expenses, and its CDM-related expenses, which may be partially controllable by the utility's management.

   i. On what basis has PSE concluded that this variable is a suitable proxy for externally-mandated CDM expenses as a cost driver?
   ii. How does this variable, as defined, satisfy the "independence" criterion as documented by PSE on pages 15-16?

Response:

a) This is not known. U.S. distributors are not required to detail their CDM expenses in the FERC Form 1. U.S. utilities do report CDM expenses to the Energy Information Association (EIA) in form EIA-861. PSE has investigated this data and it is unclear where utilities are putting these expenses on the FERC Form 1. It is PSE's belief that some distributors put CDM expenses in the customer service and information cost category, and others do not.

b) This varies by state.

c) Costs related to Hydro One's CDM delivery are recorded through the Global Adjustment and are not part of Hydro One's distribution or transmission OM&A charges. Hydro One reports its CDM costs to the IESO on a monthly basis.

d) Please see response to Exhibit I-10-Staff-043, response k).

OEB Staff Interrogatory # 46

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02 Page: 4/A-03-02-02 Page: 20

Stretch Factor and PSE Total Cost Benchmarking Study

On page 20 of its total cost benchmarking study updated in May 2017, PSE concludes:

> *"The current recommendation of 0.45% differs from the recommendation of 0.60% found in the March 2017 Report. Due to the addition of the 2016 result for Hydro One, the most recent 3-year result is now below the 25.0% stretch factor threshold set by the Board.*
>
> *This 0.45% recommendation comes with the caveat that the most recently available benchmarking scores should be used as the basis for the stretch factor. Therefore,* ***whenever data for additional years becomes available and possible to incorporate into the benchmarking evaluation, then PSE's stretch factor recommendation would be adjusted to reflect the more recent result.***
>
> *For 2017-2022, average projected total cost levels of Hydro One are above benchmark expectations by 22% for the whole period.* ***In the 2018 test year, Hydro One's total costs are 21.4% above benchmark expectations.*** *Based on the 4th Generation IR stretch factor thresholds, Hydro One would be assigned a stretch factor of 0.45% based on these projections." [Emphasis added]*

Interrogatory:

a) For clarification, is PSE recommending that the 0.45% stretch factor be applicable for the 2018 test year or for the full five-year term of the Hydro One's proposed Custom IR plan?

b) Is PSE suggesting that the total cost benchmarking study be updated annually? If so, would this entail updating data for all utilities (i.e., the 380 U.S. "peer" utilities as well as Hydro One)? If yes, then how much work would this entail, and by what process would the results be reviewed and approved for establishing the stretch factor for adjusting Hydro One's distribution rates for each year from 2019 to 2022?

c) Hydro One has proposed that the 0.45% stretch factor be held constant throughout the five-year term. If PSE is proposing that the stretch factor be updated annually, why has Hydro One made its proposal to hold the stretch factor constant?

Response:

a) PSE is recommending a 0.45% stretch factor for the full five-year term of the Custom IR period.

b) Please refer to Exhibit I-8-Staff-022, part b).

c) Not applicable, as PSE is proposing the 0.45% stretch factor apply to the five-year term.

OEB Staff Interrogatory # 47

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.5 Page: 2/ Table 17- Productivity Savings

Table 17 shows the detailed productivity savings that Hydro One has estimated for the capital and OM&A programs in its application, by year. Hydro One states that these savings are factored into the capital and OM&A plans.

Interrogatory:

a) Are the savings for Procurement and Administration categorized as capital or OM&A in nature? If mixed please provide a disaggregation.

b) It is easy to see how OM&A productivity savings in 2018 can be factored into the 2018 revenue requirement and hence reflected in 2018 distribution rates to recover that revenue requirement, all else being equal. Similarly, with the forecasted capital budget which is factored into the forecasted rate base for each year, it is easy to see how the capital productivity savings can be factored into each year's revenue requirement. However, Hydro One has proposed that the OM&A component of each year's revenue requirement is adjusted formulaically by inflation-less-productivity for the period 2019-2022.

   Please explain how the expensed productivity savings for 2019-2022 are factored into the revenue requirement derivation so that customers receive the benefits of these savings.

Response:

a) Please see response to Exhibit I-8-Staff-018, part a).

b) Over the course of the IR term (2019-2022), customers will see the benefit of a stable OM&A envelope that is increasing at a rate less than inflation (i.e. inflation minus stretch factor). The identified productivity savings will be used to offset the upwards inflationary cost pressures of other elements of Hydro One's OM&A envelope. Through the Custom IR mechanism, customers will be fully protected and Hydro One will fully bear the cost risk in the event that it does not achieve its forecast productivity savings. If Hydro One is able to materially exceed its expected productivity savings, customers will share in the benefit of the reduced costs through the Earnings Sharing Mechanism proposed in Exhibit A, Tab 3, Schedule 2. When Hydro One rebases in 2023, its new OM&A envelope will be lower than it would otherwise have been and any remaining impact of the achieved productivity savings will be fully shared with rate payers.

OEB Staff Interrogatory # 48

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6 – Benchmarking

On page 1 of this exhibit, Hydro One states:

> *"In the Decision in Hydro One's last Distribution Rate Application for the 2015 to 2019 rates (EB-2013-0416), dated March 12, 2015, the OEB found that the proposed plan showed limited prospects for continuous improvement, lacked externally imposed improvement incentives, included limited cost and productivity benchmarking support, and failed to demonstrate value to customers commensurate with the forecast spending. To address the perceived shortcomings in the application, the OEB directed Hydro One to undertake several studies and submit reports.*
>
> *The undertaking of these studies and reports presented Hydro One with the opportunity to demonstrate continuous improvement by different means: comparison to self; comparison to others; and unit cost trending analysis. This will assist Hydro One align its performance outcomes with those of the RRF.*
>
> *Hydro One also challenged itself, venturing further ahead than just undertaking the studies and reports asked of it by the OEB. Hydro One identified other studies that would help it perform more efficiently, develop a culture of continuous improvement and stay on the path to excellence in execution."*

As described in the pages following in this exhibit, it appears that IT Budget is the only benchmarking study of an operational nature and filed in the application that Hydro One has done of its own initiative. The total cost benchmarking study conducted by PSE also appears to not have been directed; however, OEB staff sees this as complementary to the TFP analyses also conducted by PSE.

Interrogatory:

a) Please confirm, correct or clarify OEB staff's understanding of the filed benchmarking studies and whether they were directed or conducted by Hydro One of its own initiative.

b) Are there other areas of its capital and operations programs that Hydro One considered suitable for benchmarking? If so, please provide a list, including why these were not completed or the status of each that is still ongoing, and when Hydro One expects that the study would be completed.

c) Please identify other benchmarking studies that Hydro One participates in and are conducted by other organizations such as the Canadian Electricity Association or the Edison Electrical Institute. Provide copies of any recent studies or, alternatively, a synopsis describing each study and the results. Also, indicate how each study has informed Hydro One with respect to its capital and operational management of its electric distribution business.

Response:

a) Of the benchmarking studies included in the Application, the following were completed of Hydro One's own initiative:
   - A Total Cost Benchmarking Study, completed by PSE, and
   - An IT Budget Assessment Study, completed by Gartner Consulting.

   The other benchmarking studies filed with the Application were ordered by the OEB in its Decision on Hydro One's last custom distribution rate application (EB-2013-0416).

   Hydro One did expand the scope of the total factor productivity (TFP) study ordered by the OEB (and completed by PSE). The OEB ordered Hydro One to file a study measuring "Hydro One's own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB." Hydro One expanded the scope to include an update to the Ontario industry TFP trend analysis that was conducted in the OEB's 4th Generation IR proceeding (EB-2010-0379).

   The OEB also directed Hydro One to file an analysis of its vegetation management program similar to a study that had been filed by Hydro One in a prior proceeding. Hydro One provided such that study, completed by CN Utilities, in Attachment 2 of Section 1.6 of Exhibit B1, Tab 1, Schedule 1. Hydro One continued to further explore opportunities for continuous improvement in vegetation management which led Hydro One to voluntarily initiate an additional review of its vegetation management program. This additional review was completed by Clear Path Utility Solutions LLC and is provided as Attachment 2 to Exhibit Q, Tab 1, Schedule 1.

b) Hydro One assumes that this question is focused on unit cost benchmarking.

Hydro One considers program OM&A spending a suitable area for benchmarking as the work is predictable, repeatable, and accomplished in relatively standard units. In this Application, Hydro One has filed a benchmarking study by CN Utility for its vegetation management program which is its largest OM&A work program.

Benchmarking capital program spending might be suitable, if the assets and units of work were standard. In Hydro One's case, the only capital program spending program that might fit this description is its wood pole replacement program (ISD SR-09). In this Application, Hydro One has filed a pole replacement and substation refurbishment benchmarking study by Navigant Consulting for its wood pole replacement program (the "Navigant Study"). (See Attachment 1 to Section 1.6 of the DSP found at Exhibit B1, Tab 1, Schedule 1. For the ISDs, please see section 3.8 of the DSP.

In Hydro One's view, projects cannot be benchmarked because of their diversity. Hydro One's stations refurbishment investments are diverse with different drivers and characteristics. The Navigant Study observes that "individual station refurbishment activities are varied within and across utilities" and that "As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile".

Hydro One is mindful that, to be useful, benchmarking requires a relevant normaliser (i.e. unit of measurement), relevant and willing participant base (i.e. peer group), and a consistent, reliable dataset amongst peers. Moreover, results are useful only to the extent that they are properly contextualized with differences in business conditions that may impact performance over time or across peer groups.

In this Application, Hydro One has filed benchmarking studies for its major areas outside of reactive or demand investments: vegetation management, pole replacements and station refurbishments.

c) Please refer to Exhibit I-03-SEC-003.

OEB Staff Interrogatory # 49

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6.3.4– Benchmarking – IT Budget

Interrogatory:

Under Recommendation 2, with respect to (IT) Capitalization Policy, Hydro One states that its Finance group is *"reviewing the current capitalization policy of $2M and will be making a decision in the near future on a potential reduction of the minimum threshold"* based on the benchmarking study's analysis that shows the peer group have capitalization thresholds of $250K to $500K.

a) Has any change in IT capitalization policy been reflected in the budget plan or the forecasted revenue requirement for 2018-2022? If so, please explain.

b) Please explain what would be the efficiencies resulting from a change in the capitalization. Further, explain the impacts on Hydro One from a financial and credit metrics impact, on Hydro One's investors, and on Hydro One's ratepayers.

Response:

a) Hydro One reviewed elements of the enterprise capitalization policy, as many organizations do in the normal course of business and one of the elements reviewed was the capitalization threshold for IT projects based on benchmarking against other organizations. The result of the review is that the threshold was reduced from $2M to $500K, effective Jan 1, 2018. The change was approved in December 2017 and as such is not reflected in the business plan or forecasted revenue requirement for 2018-2022.

b) Please refer to Exhibit I-10-Staff-62.

   The threshold being reduced will ultimately result in an increase in capitalized costs and depreciation, but will also result in lower OM&A. This change in application of the capitalization policy will result in better matching of costs with the benefit they provide. The capitalized assets will be charged over the period in which the benefit is provided and recovered from ratepayers over their useful lives. The change in threshold is not anticipated to have a material impact on our credit metrics. This revision does not materially change the capital or OM&A forecasts in the Application.

OEB Staff Interrogatory # 50

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 – Distribution Unit Cost Benchmarking Study: Pole Replacement and Substation Refurbishment/pages 4 and 12 - Credentials and Project Cost

Interrogatory:

Pursuant to an OEB order to conduct an external unit cost benchmarking study of its distribution pole replacement and station refurbishment programs and an internal unit cost trend analysis, Hydro One commissioned Navigant and First Quartile ("the authors") to perform such a study. The document Distribution Unit Cost Benchmarking Study ("Unit Cost Report") provides an overview of their work.

a) Please provide a list of similar projects the authors have done, referencing reports that are in the public domain.

b) Please provide the terms of engagement or other instructions from Hydro One to the authors for conducting the work.

c) Was a more thorough statistical report prepared? If so, please provide it.

Response:

a) The authors have completed a number of similar projects, however, most of the reports are not in the public domain. No reports that are precisely about pole replacement or substation refurbishment are in the public domain. A few projects where the authors filed benchmarking reports in a regulatory proceeding include previous reports for Hydro One Networks (combined Navigant and First Quartile), Great Lakes Power (First Quartile), Direct Energy (First Quartile), and ATCO Electric (First Quartile authors while at PA Consulting).

b) As outlined in the Unit Cost Report, Hydro One engaged Navigant and First Quartile to design a benchmarking study to:

Witness: NAVIGANT

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

c) No other statistical report was prepared. Various individual analyses were conducted, with the findings reported in the final report. A summary report was prepared showing comparisons of the demographic variables, maintenance activity, cost results, etc. in a series of charts and graphs. That report was provided to the companies who shared data, as the quid pro quo for their willingness to provide the data. No statistical analysis as such was included in that report.

OEB Staff Interrogatory # 51

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 1, 4-5 and 20 - Sample

The authors state on page 1 that:

> *"This work leveraged First Quartile Consulting's existing transmission and distribution benchmarking program participants as well as additional companies recruited specifically for this study."*

Further, on pages 4-5:

> *"The goal of the comparison group selection is to find utilities that represent the industry, with both similarities and differences from Hydro One. Similar utilities provide the opportunity for direct comparisons of outcomes (costs, service levels, etc.) while dissimilar utilities offer the opportunity to investigate a broader array of practices that might be beneficial for Hydro One. Companies across North America were identified and evaluated for their usefulness as part of the comparison group. As a result, 29 North American Utilities were approached to participate in the study...*
>
> *A concerted effort was made, as requested by stakeholders, to include more Canadian utilities. However, because there is no requirement for them to participate, and the effort for them to participate is significant, only a few Canadian utilities agreed and provided data for the study. As shown in Figure 5, the utilities in the comparison group are located throughout Canada and the U.S. There are several large companies, some smaller ones, with regulatory circumstances and weather patterns similar and different from Ontario. The net result is a reasonably representative and useful comparison group."*

The authors also state on page 20 that Hydro One has the "*second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile).*"

Interrogatory:

a) How many (and specifically which) participants in the study had already participated in a First Quartile or Navigant benchmarking study, and how many (and which) were added specifically for this study?

b) Please identify the companies that were invited but chose not to participate. How many of these non-participants have been in First Quartile or Navigant benchmarking programs?

c) The resulting peer group includes many utilities (e.g. Austin, SCE, Oncor, Centerpoint, Com Ed, PECO, and PEPCO) which serve large urban areas. Several operate in markedly different climates with less extensive forestation. How then is this comparison group "reasonably representative"? Should the "dissimilar utilities" be included in the unit cost calculations? Can you identify a subset of the peers that are especially representative?

d) Since the authors use unit cost metrics, there is an automatic (if imperfect) control for differences in the operating scale of sampled utilities. Do you agree that peer group selection should therefore be based chiefly on criteria other than operating scale such as the "demographic scale variables" listed on p. 4? What are the key drivers which should ideally determine peer groups for distribution poles and substations? What is the relative importance of these drivers? Is there any reason why the peer groups for poles and substations should be the same?

e) The sample period for the study was 2012-14. Since HON filed in mid-2017 to set rates for several future years, please explain why data for 2015 and 2016 were not included.

Response:

a) The companies are listed in the table below. In the left column are the 16 companies who have participated in recent First Quartile studies, and in the right column are the four other companies who agreed to participate in this study specifically for Hydro One.

1QC Participants	New for Hydro One Study
Atlantic City Electric	Essex Powerlines
Austin Energy	PowerStream
BC Hydro	Veridian
CenterPoint Energy	We Energies
Commonwealth Edison	
CPS Energy	
Delmarva Power	
Hydro-Québec	
Kansas City Power & Light	
Oncor Electric Delivery	
PECO Energy	
PEPCO	
Public Service Electric & Gas	
Southern California Edison	
Tucson Electric Power	
Westar Energy	

b) The table below shows most of the invited companies who chose not to participate. The column on the left shows those who participated in recent 1QC studies, and the right column shows companies who were contacted specifically for this study. The table is incomplete, because complete notes were not kept of all the companies invited to participate.

1QC Participants	Specific for Hydro One study
Arizona Public Service	ATCO Electric
East Kentucky Power Cooperative	AvanGrid
Exelon - BGE	FortisOntario
FirstEnergy	Manitoba Hydro
PSEG-Long Island	National Grid
	New Brunswick Power
	Nova Scotia Power
	Pacific Gas & Electric
	Sask Power

c) The goal of the benchmarking study was to have a sample of comparison utilities that are representative of the industry. In addition to producing a more realistic picture of the performance of the utility under study, this approach also provides the opportunity to find a broader array of operating practices that might be adapted for use at the subject utility.

The utilities in the comparison panel are representative of the utility industry, none more so than any other.

Some of the panel companies share more demographic similarities to Hydro One. Hydro One is characterized by a large, low-density system, with mostly overhead lines in a territory subject to significant winter weather extremes. Oncor, in addition to the Dallas metro area, serves a huge rural territory, with extremes of rain forests and deserts from east to west, and is subject to extreme summer and winter storms. Southern California Edison serves a large, highly populated territory, but doesn't serve most of Los Angeles or the nearby large cities (L.A., Anaheim, Burbank, Glendale, etc. all have municipal utilities). It does serve the surrounding area, with large swaths of desert, mountains, and with substantial variance in the weather in the outlying territory. BC Hydro serves a large population center, but also serves a large non-urban territory, and the same can be said for Hydro Quebec. Westar Energy serves a very broad rural territory, with two small cities, and significant weather extremes. These companies have large majority overhead systems, with substantial vegetation.

d) As noted in the answer to part c) above, the goal is to have a representative sample of utilities to provide a proxy for the entire utility industry. From a practical standpoint, having utilities that are too small might mean there isn't enough activity in a given area for a given year or period of years to make a useful comparator, which puts something of a lower limit on the size of utilities useful for the comparison. The key driver is essentially having utilities with enough activity in pole replacement and substation refurbishment. There is no particular reason why the peer groups should be the same, or that they should be different.

e) The study was commissioned during 2015. At that time, 2014 was the most recent year for which actual data was available.

OEB Staff Interrogatory # 52

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 – Distribution Unit Cost Benchmarking Study: Pole Replacement and Substation Refurbishment/pp 4 &12

On page 4 of this Navigant study, it is identified that collected information included

> *"Number of in-service poles by material type and age profile" and "Planned Service Life for different pole types."*

On page 12, Figures 14 and 15 are labelled as pertaining sole with respect to wood poles.

Interrogatory:

a) Does the Pole Replacement/Refurbishment Unit Cost Benchmarking study only pertain to wood poles, or to all poles? Are the other figures shown in the study with respect to all poles, or only for wood poles?

b) Some of the utilities identified as being contacted for the pole benchmarking study would appear to operate in more urbanized areas relative to Hydro One. While Hydro One does operate in some urban and suburban areas, primarily service areas of acquired utilities, this is a smaller fraction of its poles and hence pole installation, inspection and refurbishment/replacement costs. In addition to the three Ontario distributors contacted (Veridian Connections Inc., Essex Powerlines, and PowerStream (now part of Alectra)), as identified on the map on page 5, other U.S. utilities such as Austin Energy and CPS Energy may also operate in more densely populated and built-up areas on a percentage basis. They may also rely on poles constructed from other materials. How has Navigant and/or Hydro One taken into account the different operating characteristics, including different pole types, in the analysis and conclusions in this study?

Response:

a) The study pertains solely to wood poles, which make up 99%[1] of Hydro One's distribution pole population. In the annual benchmark studies conducted by First Quartile, data is gathered on all types of distribution poles, of which wood is by far the dominant type. All the figures shown in the charts and graphs, and all the analysis, are focused on wood poles.

b) The study focused on wood poles, which make up 99% of Hydro One's distribution pole population. Regarding the differences in operating conditions created by differences in density, the focus of the study was on the differences in practices (e.g. frequency of various activities, intrusiveness of pole inspection, etc.). As noted in the report, demographic elements investigated included the planned life of the poles, the percent of poles installed off-road, the percent of poles installed in soft soil, the average travel time to get to poles, and average age of poles, and the analysis showed those elements had little to no statistical impact on the overall cost results.

[1] For a detailed breakdown, see Section 2.3.2.1, Table 44 of Exhibit B1, Tab 1, Schedule 1.

OEB Staff Interrogatory # 53

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 7 - Cost Comparisons

On page 7 of the report, the authors state:

> *"The cost analysis portion of the study looked at pole replacement from several aspects – lifecycle costs per pole across all poles, unit costs per pole worked on in a year, and then costs of individual aspects of the pole program such as inspection costs, replacement costs, and refurbishment costs."*

Interrogatory:

a) Please provide a detailed explanation of how "life cycle costs per pole" were calculated.

b) How did the authors ensure standardization of the reported cost data? For example, were there differences in overhead, capitalization, and benefit accounting? If so, how were adjustments made?

c) Please confirm that the study did not benchmark the capital cost (e.g. depreciation and return on rate base), or the unit total cost of poles or substations.

d) How does a focus on cost per pole address commission concerns about the number of annual pole replacements?

Response:

a) The lifecycle costs were calculated as the sum of all costs for installation, inspection, and refurbishment for a given pole during its life. The chart shown on that page of the report annualizes those costs by normalising for the average life of a pole for each utility. Perhaps the easiest way to show the calculation is to provide an example spreadsheet.

1	A	B	C	D	E	F	G	H
2		Installation costs	Refurbishment	Replacement	Inspection Costs	Life	Total lifetime Costs	Annualized total cost
3	90% of poles - no problem	Install yr 1	none	none	Inspect every 5 years 5-50	50 years	Install + 10 inspections	Total lifetime cost/50
4		$8,266			$276	50	$8,542	$171
5	10% of poles - refurbish at 20 years, replace at 40 years	Install yr 1	Refurbish year 20	Replace yr 40	Inspect every 10 yrs - 10-90	90 years	Install plus refurb plus replace plus 9 inspections	Total lifetime cost/90
6		$8,266	$947	$8,266	$351	90	$17,830	$198
7								
8							Average Total Annual Per-Pole Costs - Refurbishment Approach	$174

Row 3 shows the circumstance for 90% of the poles – they never need refurbishment, and they last for 50 years, with inspections every 5 years. Row 5 shows the scenario for 10% of the poles – they are re-furbished at 20 years, replaced at 40 years, and the second pole lasts for another 50 years without refurbishment. Inspections are executed every 10 years. Activity costs are shown in rows 4 and 6. The lifetime cost for a given pole is calculated in column G. That total is annualized in column H by dividing by the total lifetime of the combined set of poles. Cell H8 represents the overall total annualized cost, calculated by weighting cell H4 by 90% and cell H7 by 10%, and summing the total.

Note that no time value of money is included in the calculations – it is strictly nominal, based on the assumptions as presented.

b) Cost information gathered was gathered from each of the participating companies in defined categories. For example, the following table was used to capture costs of pole replacement:

	Company Direct Labor ($)	Company Direct Labor Overheads ($)	Equipment Cost ($)	Material Cost ($)	Contract Labor/ Services Cost ($)	Company Labor Hours
2012						
2013						
2014						
Breakdown Unavailable						

Then within the costs from that table, the direct labor costs and direct labor overheads were broken into the percentages in the following tables:

	Company Direct Labor- % Breakdown
Regular Staff Base Pay	
Regular Staff Overtime	
Non-Regular Staff Base Pay	
Non-Regular Staff Overtime	
Pension	
Health & Welfare Benefits	
Government Obigations	
Other Direct Labor Costs	
Total (should total to 100%)	0%

	Company Direct Labor- % Breakdown
Supervisory Overheads	
Administrative Support	
Cost Allocations from Support Organizations	
Other Overheads Applied to Direct Labor	
Total (should total to 100%)	0%

The differences were investigated to assure that all major categories of costs were included for all the companies, but no detailed analysis was conducted to assess the differences in results caused by different accounting treatment.

c) The study did not include financing costs or the impact of accounting and regulatory constructs such as capitalization rules, deemed capital structures and cost of capital, etc.

d) Per the direction from the Board to Hydro One, the study was commissioned as a “Unit Cost” study. It didn’t benchmark the number of pole replacements.

OEB Staff Interrogatory # 54

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 6 - Input Prices

The authors state on page 6 of their report that:

> *"Because the comparison group includes both U.S. and Canadian utilities, the first normalization step was to convert all cost figures into Canadian currency. All charts and tables showing dollar values are based on Canadian dollars. The conversion rate used for data submitted by U.S. companies was the average currency exchange rate in effect during the year in which the work was performed. The shift in the exchange rate in 2014, the Canadian companies look slightly more cost effective, despite any change in their actions. All values are presented in nominal dollars, and costs were not adjusted for inflation when taking an average or aggregating across multiple years."*

Interrogatory:

a) Why were exchange rates employed for currency conversion rather than the measures of purchasing power parity used in PSE's benchmarking study for Hydro One?

b) Have the authors used exchange rates in all of their transnational cost benchmarking studies?

c) Several sampled utilities serve large urban areas where high wage rates are common. Did the authors not control for differences in local input prices of sampled utilities, like PSE did in its benchmarking study? If not, why not?

d) Doesn't the lack of control for inflation limit the accuracy of the performance trend results that the Board requested?

Response:

a) Exchange rates are the means by which Navigant and First Quartile chose to make the comparisons, in line with the way they have conducted many similar studies. They were not asked to review the work of PSE or their methodology. Further, the costs of materials (e.g. poles) will be affected directly by exchange rates at the time of purchase, which gives a reasonable approximation of the purchasing power parity.

b) For the benchmarking studies conducted by First Quartile, exchange rates are routinely used to compare companies using different currencies. This includes the annual studies the company runs that involve U.S. and Canadian companies, and it includes special one-off studies done for companies in Asia and Europe. In previous instances where the authors worked for other consulting firms, they also used exchange rates in comparing companies in Asia, Australia, Africa, and South America, in addition to North America.

c) No adjustments were made for differences in local input prices. The purpose of the study was to understand the unit cost outcomes. A variety of inputs, including wage rates, local availability of poles and other materials, individual company work rules, and others affect those outcomes. Each company has to manage its own balance of those input variables and companies themselves adjust their operating practices to accommodate their unique situations.

d) The inflation rates during the period of 2012-2014 were approximately 1.5%, and even lower during the ensuing two years. Given that very small figure, and the relatively much larger differences in costs between the utilities under study for the two focus areas, the added complexity of addressing inflation rates wasn’t considered material for the analysis.

OEB Staff Interrogatory # 55

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 7 - Pole Program Costs

The authors state on page 7 that:

> *"Another way to view pole program costs is through the unit cost of the poles touched (or treated) during an individual year. This is affected by the choices of how many poles to work on during a year, and what is done to those poles. "Poles touched" in this case is those inspected, refurbished, or replaced during the year, so depending on the mix of work done, the costs can vary year to year for an individual company."*

The authors state on page 8 that:

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

Interrogatory:

Please confirm that Figures 8 and 9 do not control for differences in the mix of procedures of the sampled companies.

Response:

Confirmed.

OEB Staff Interrogatory # 56

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 15 – Pole Replacement Costs

Interrogatory:

Please confirm that the pole replacement costs shown in Figures 18 and 19 on page 15 include the costs of the replacement pole as well as the costs of emplacement. Are costs for removal of the replaced poles also included?

Response:

The costs include the costs of the pole and its installation. For the majority of pole replacements (90-95%) the removal is included as well. In a few instances related to joint-use poles, there is an arrangement for the other party to do the removal, so those costs aren't included (or incurred).

OEB Staff Interrogatory # 57

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 17 – Multiple Scale Variables

The authors state on page 17 that:

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

The authors similarly compute two unit cost metrics for substation-centric refurbishment projects. They state on page 19 that:

> *"Hydro One's projects...fall at different points within the comparative cost spectrum, whether measured on a per-transformer or a per-MVA basis."*

Interrogatory:

a) What research has been conducted by the authors to ascertain the relative importance of the number of transformers and MVA capacity as drivers of substation cost?

b) How is the OEB to weight multiple unit cost comparisons that use different scales for the two metrics?

Response:

a) Over a span of years of conducting annual benchmarking studies, First Quartile has experimented with different normalizing factors for substation costs. The best cost predictor on an overall, long-term, basis is the level of invested capital (the asset base). That is followed by MVA of capacity and the number of transformers. In this case, where the analysis is about individual stations, and typically older ones being refurbished/replaced, the asset base might tend to give misleading results, so the capacity and number of transformers were used.

b) The relative ranking of the majority of the individual projects that were benchmarked does not change significantly regardless of the scale or metric used.

OEB Staff Interrogatory # 58

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 17 – Substantion Refurbishments

The authors state on page 17 that

> *"Since companies take different approaches to substation refurbishment, it was necessary to group the refurbishment work into several categories – full station rebuild projects, substation-centric projects, and component-based projects."*

Interrogatory:

a) Please provide a thorough description/explanation of these categories.

b) Does the cost of a full substation rebuild project include the new equipment or just the cost of its installation?

c) Please appraise Hydro One's overall substation refurbishment cost per refurbishment project and its refurbishment cost per transformer bank and substation MVA.

Response:

a) The definitions used in the benchmarking study were as follows:

Full Station Rebuild	A refurbishment project at a specific substation is considered when certain critical components are determined to be in need of replacement. At that time, the entire substation is completely rebuilt on-site with all existing components being removed/demolished and replaced with new components.
Substation-Centric	A refurbishment project at a specific substation is considered when certain critical components are determined to be in need of replacement or major rebuild/reconditioning work. At that time, all of the other substation components are evaluated and a single, comprehensive substation refurbishment project is initiated to replace or rebuild/recondition all components of the substation that require attention.
Component-Based	Individual substation components are evaluated separately and any needed component replacement, rebuild or reconditioning work is completed through separate, component-focused refurbishment projects over a period of several years.

b) The costs collected for the benchmarking study included the costs of new equipment and the labor required to remove existing equipment and install the new equipment. Engineering and commissioning labor costs were also included.

c) As stated in the Unit Cost Report, Hydro One's costs for individual substation refurbishments are within range observed across the comparison utilities. As with most utilities, the cost of individual Hydro One refurbishment projects ranges from first to fourth quartile. This conclusion applies across the different metrics.

OEB Staff Interrogatory # 59

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A01 Page: 20 – Substation Refurbishments

The authors state on page 20 that:

> *"Hydro One's current emphasis on station centric and full station rebuild projects is not unique within the comparison group and is related to several demographic factors that distinguish Hydro One:*
>
> - *Higher than average transformer loadings at non-coincident peak;*
> - *An older age profile for in-service power transformers;*
> - *Highest percentage of single transformer substations; and*
> - *Second highest percentage of rural substations (substations serving areas with 50 or fewer customers per square mile)."*

Interrogatory:

Please explain how the third and fourth "demographic" factors on this list affect the approach to refurbishments by any utility.

Response:

The third and fourth demographic factors are common for distribution utilities that serve small communities that are widely disbursed across a large geographic area. Those communities are often served by only one, low capacity single transformer distribution substation, because there is insufficient customer load to make it cost-effective to install two or more power transformers and automatic bus-tie switches to transfer load when a transformer failure occurs, or when a transformer must be taken out of service for maintenance or replacement. Also, there typically is no capability to transfer the load served by the single transformer substation to neighboring substations through distribution line switching, because there are no neighboring substations which are close enough to practically provide such backup support.

Due to these limitations of the overall system configuration, the entire distribution substation must be taken out of service to complete any significant maintenance, refurbishment or replacement work on the major substation components such as the power transformer, its high side breaker or switch-fuse unit, and/or its low side bus-work. In order to maintain continuity of service to customers while such work is being performed, utilities typically move mobile substations to the site to serve customer load while equipment is being maintained, refurbished or replaced, and they can achieve better overall efficiencies by accomplishing as much needed work as possible each time that a mobile substation is moved to a given site. That influences those utilities to place greater emphasis on full station rebuild and substation-centric projects in their overall substation refurbishment program, and less emphasis on component-based projects.

OEB Staff Interrogatory # 60

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6/ Appendix 2/CN Utility Consulting Hydro One Vegetation Management Benchmarking Study/pg 14

On page 14, CN Utility Consulting states:

> *"Customer density is important when analyzing the cost to the customer and reliability. In 2011-2015 each Hydro One customer spent on average $99.36 for UVM. Although this is above the average ($35.13 in 2015) for utilities in their peer group, it is important to note some extenuating circumstances that contribute to higher cost for Hydro One customers …"*

Interrogatory:

Is the $99.36 per customer an annual number or the average cost per customer for the 2011-2015 period?

Response:

$99.36 is the average annual cost per customer for the 2011-2015 period. This is a calculated metric based on the number of customers in 2015 and the total UVM costs. The number of customers changes each year as well as the total UVM expenditures. For all companies we only received the 2015 number of customers. Hence, we only provided the 2015 average annual cost per customer per company of the peer group. We averaged 2011-2015 costs for Hydro One because there was a sharp decrease in their 2015 expenditures. If we had used only the 2015 Hydro One costs, the average annual cost per Hydro One customer would have been $89.17.

Note: For a residential customer the average annual cost is considerably lower because electric rates are volumetric. In comparison, commercial and industrial customers pay a larger percent of the vegetation management costs. This is discussed in the report.

Witness: CN Utility Consulting

OEB Staff Interrogatory # 61

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6-A02 CN Utility Consulting Hydro One Vegetation Management Benchmarking Study/p. 48

On page 48, CN Utility Consulting states:

> *"Although Hydro One compares favorably using the metric of outages per kilometre, it will have to make improvements in reliability performance for the foreseeable future. First and foremost, the UVM department should be investigating tree-caused outages. Hydro One* ***is the only utility in the survey where the vegetation management department does not investigate tree-related outages.*** *It is also unknown how many tree-related outages are categorized as unknown or weather-related." [Emphasis added]*

Interrogatory:

a) Why does Hydro One not investigate and further document tree-related outages?

b) What plans does Hydro One have with respect to CNUC's assessment and recommendations on pages 48-49 of CNUC's study?

Response:

a) As documented on page 44 in Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Hydro One has initiated tree outage investigation process, which is a result of the peer benchmarking exercise.

b) As noted in part (a), Hydro One has implemented the outage investigation process. Additionally, as part of the new vegetation management strategy outlined on page 14 in Exhibit Q, Tab 1, Schedule 1, Hydro One will continue conducting these detailed outage investigations within the Quality Assurance and Quality Control program.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 62

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.6 Page: 11-12
B1-01-01 Section 1.6-A03/ Gartner IT Budget Assessment

Hydro One notes that it undertook this study of its own initiative – i.e., it was to address a directive from the OEB from a prior decision. Table 26 provides a summary of the key findings, while Table 27 (reproduced below), provides a summary of recommendations:

#	**Recommended Actions**
1	Optimize enterprise computing and storage costs and increase server virtualization.
2	Reduce materiality threshold for IT capital expenditure.
3	Review IT organization structure and identify any duplication between roles and responsibilities of retained staff and outsourced service provider.

Hydro One states that more information is provided in section 1.6.4 [sic – 1.6.3.4], but there is little additional information there, and the discussion regarding recommendations 2 and 3 states that work is ongoing.

Interrogatory:

a) What has Hydro One done or is it doing, and when are decisions and implementation of these expected to occur.

b) How has Hydro One reflected any decisions taken to date regarding the recommendations from the Gartner study? For recommendations 2 and 3, given that their assessments seem to be ongoing, how has Hydro One factored in, or propose to factor in, any cost, cost efficiencies or productivity improvements as a results of decisions taken during the five-year term of the proposed Custom IR plan.

Response:

The Gartner study was initiated by Hydro One internally and not mandated by the OEB i.e., it was not undertaken to address a directive from the OEB from a prior decision. This study was included in the Application as a relevant benchmarking study that Hydro One commissioned. The purpose of this study was to conduct an IT budget assessment in terms of enterprise-level metrics and the distribution of IT spending. The study was an input to the development of IT productivity savings initiatives described in Exhibit B1, Tab 1, Schedule 1 (the "DSP"), section 1.5.

a) Hydro One has reviewed elements of its enterprise capitalization policy, as many organizations do in the normal course. One of the elements reviewed was the capitalization threshold for IT projects. (This review was informed by benchmarking against other organizations). The result of the review is that the threshold was reduced from $2 million to $500,000, effective Jan 1, 2018. This revision does not materially change the capital or OMA forecasts in the Application.

b) The Gartner study was an input in the development of a 2017-2022 costs savings program, listed as IT Productivity initiative in Section 1.5 of the DSP. For recommendations 2 and 3, there are no additional cost efficiencies or productivity improvements to be included as a result of the decisions within the five-year term of the proposed Custom IR plan.

OEB Staff Interrogatory # 63

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

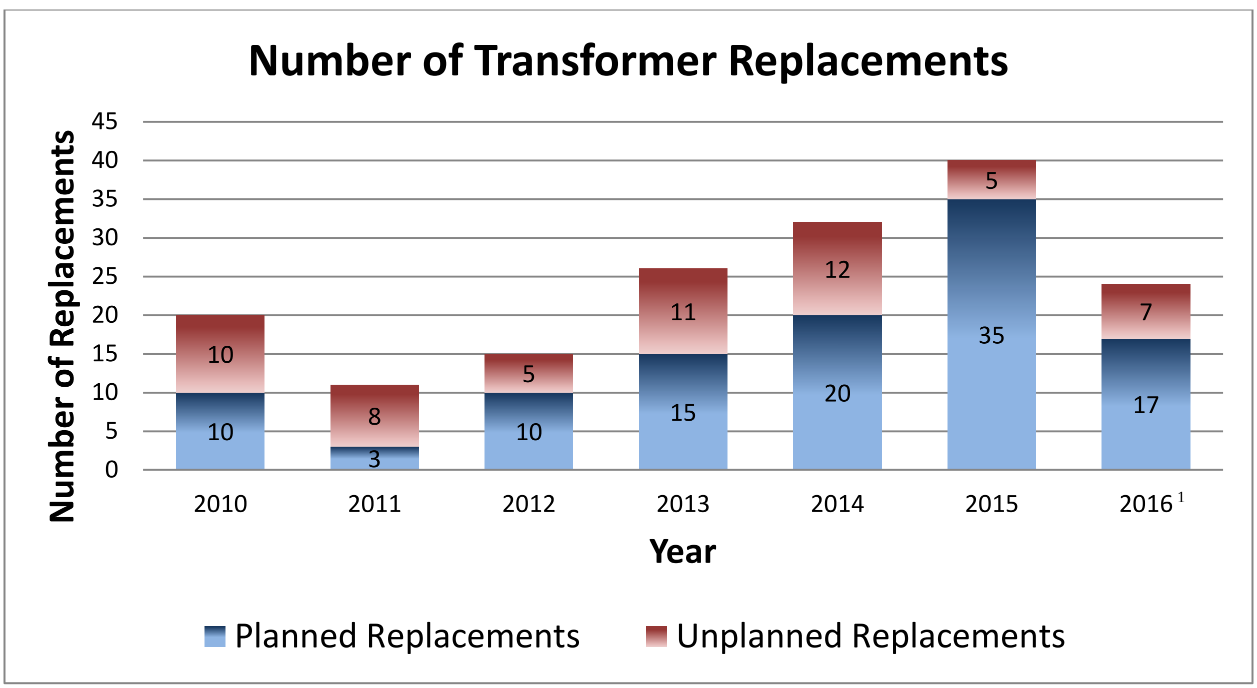
B1-01-01 Section 2.3 Page: 13/Figure 19 – Number of Transformer Replacements

Interrogatory:

Please provide a variation on Figure 19 showing the number of transformer replacements by year, segregating by Planned versus Unplanned replacements.

Response:

The figure below provides a variation on Figure 19 from Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3 showing the number of planned versus unplanned station transformer replacements.



[1] The year 2016 transformer replacements in this chart reflect actual replacements. The 27 transformer replacements shown in the original Figure 19 was based on a 2016 forecast.

Building Owners and Managers Association Toronto Interrogatory # 85

Issue:

Issue 13: Are the annual updates proposed by Hydro One appropriate?

Reference:

A-07-01 Page: 3

Interrogatory:

What was the scheduled closing date for Norfolk acquisition? Why was the closing delayed for that period? Why did the 2014 costs increase by $1.5 million, a loss relative to forecast of OM&A savings of $5.8 million in the MAADs application? Does Norfolk remain a separate corporation after the closing, or was it merged into Hydro One?

Response:

The Share Purchase Agreement between the Corporation of Norfolk County and Hydro One Inc. for the purchase of NPDI was signed on April 2, 2013. Hydro One subsequently filed its MAAD application to the OEB for approval to acquire NPDI on April 26, 2013. The OEB approved the application on July 3, 2014.

Hydro One's expectations of the OEB's approval period were significantly shorter, compared to the time that actually elapsed before the transaction was approved. Hydro One assumed the transaction would close prior to 2014 and therefore any cost savings achieved in 2014 would be for a full year. This was based on an eight month OEB approval time period assumption, which at the time, Hydro One believed was a reasonable estimate. OEB approval took longer than Hydro One had expected, and consequently NPDI operated as status quo until August 29, 2014 at which time it became a subsidiary of Hydro One Inc., however not integrated into Hydro One Network's operations. NPDI's distribution system was transferred to Hydro One Networks on September 1, 2015. At that time Hydro One Networks assumed all operating and asset management activities, and was then able to commence activities to achieve the forecast synergy savings.

The OM&A forecast of $5.8M was made on the basis that the OEB approval to purchase NPDI would have occurred in a timelier manner as outlined above. See Exhibit I, Tab 29, SEC-64 for further details.

NPDI's operations were merged into Hydro One Networks Inc. in September 2015 and its distribution licence was then transferred to Hydro One Networks Inc. On January 12, 2017 the OEB amended Hydro One's distribution licence to include the service territory of the former NPDI and cancelled the prior transferred licence.

Building Owners and Managers Association Toronto Interrogatory # 86

Issue:
Issue 13: Are the annual updates proposed by Hydro One appropriate?

Reference:
A-07-01 Page: 5

Interrogatory:
a) What was the incremental capital costs for the Haldimand County acquisition calculated in the same manner as those for Norfolk? Please confirm that these costs will not be recovered from HONI's ratepayers as in the Norfolk case. If not, please explain why not.

b) Please provide a detailed breakdown of these costs.

Response:
a) Hydro One assumes the first question is "Were the incremental capital costs for the Haldimand County acquisition calculated in the same manner as those for Norfolk?

Yes. Hydro One assessed the capital cost needs for Haldimand in the same manner as Norfolk. See Exhibit I, Tab 53, Schedule CCC-69.

Haldimand service area customers' base 2014 distribution rates are held frozen, less 1%, during the rate rebasing deferral period, as approved by the OEB. Hydro One will continue to fund capital and OM&A expenditures required for the Haldimand service area using these rates. Any savings, or shortfall, incurred during that deferral period will not impact legacy Hydro One distribution customers and is not recoverable from other customers.

The Board's MAAD policies and guidelines are clear. They state any savings that occur during the deferred rebasing period are available to the acquiring LDC to recover their transaction and acquisition costs. Likewise, the risk of not producing savings in any of the years during the deferral period will fall to the account of the LDC's shareholder and not be borne by customers

All acquisition costs associated with the purchase of Norfolk, Haldimand and Woodstock were charged to Hydro One's unregulated business. Hydro One does not include any forecast for acquisition costs in its revenue requirement, therefore these costs are not funded by ratepayers.

b) Acquisition costs are not included in any revenue requirement and are therefore not relevant to this application. Please see Exhibit I-29-SEC-63 for a breakdown of 2017 and 2018 capital expenditures for Haldimand.

Building Owners and Managers Association Toronto Interrogatory # 87

Issue:
Issue 13: Are the annual updates proposed by Hydro One appropriate?

Reference:
A-07-01 Page: 9

Interrogatory:
a) What were the incremental costs incurred in the Woodstock acquisition? Will these costs be recovered from ratepayers, given the fact that OM&A savings were negative in 2015 and $0.8 million (vs. $2.3 million projected in 2016)? If not, provide the balance, in excess of savings that are to be recovered.

b) Please provide a detailed breakdown of these costs, calculated in the same manner as for the Norfolk and Haldimand acquisitions.

Response:
a) All acquisition costs associated with the purchase of Norfolk, Haldimand and Woodstock were charged to Hydro One's unregulated business. Hydro One does not include any forecast for acquisition costs in its revenue requirement, therefore these costs are not funded by ratepayers.

Woodstock service area customer's base 2014 distribution rates are held frozen, less 1%, during the rate rebasing deferral period, as approved by the Board. Hydro One will continue to fund capital and OM&A expenditures required for the Woodstock service area using these rates. Any savings, or shortfall, incurred during that deferral period will not impact legacy Hydro One distribution customers and is not recoverable from other customers.

See Exhibit I, Tab 13, Schedule BOMA-86 for further information.

b) Acquisition costs are not included in any revenue requirement and are therefore not relevant to this application. Please see Exhibit I, Tab 29, Schedule SEC-63 for a breakdown of 2017 and 2018 capital expenditures for Woodstock.

Building Owners and Managers Association Toronto Interrogatory # 123

Issue:

Issue 13: Are the annual updates proposed by Hydro One appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1; DSP 2.6 Page 8

Interrogatory:

a) Will the forecast number be amended to reflect the acquisition of Peterborough Hydro?

b) What is the forecast increase or decrease (kw) over the DSP year? Please provide details.

Response:

a) No it will not. The acquisition of Peterborough Hydro, if it happens, would not impact the load forecast in this Application.

b) It is unclear what is meant by "over the DSP year". The increase in billing peak forecast (in kW) for demand-billed customers over the period of the Application is provided below. For further detail, please see in Exhibit E1, Tab 2, Schedule 1, Appendix E, Table E.8b.

Year	Demand (kW)	Change (%)
2018	44,534,208	-0.7
2019	44,074,129	-1.0
2020	44,044,395	-0.1
2021	45,049,972	2.3
2022	45,073,072	0.1

The figures include Acquired Utilities for the years 2021 and 2022 only.

Consumers Council of Canada Interrogatory # 15

Issue:

Issue 13: Are the annual updates proposed by Hydro One appropriate?

Reference:

A-03-02

Interrogatory:

Please describe in detail the annual process that HON is proposing for setting rates and making annual adjustments. Please include a proposed timeline for that process.

Response:

Hydro One expects to file annual update applications in 2019-2022. These applications are expected to be filed by the deadline for IRM applicants seeking a January 1st effective date which has typically been near the end of August. These applications would:

1) Calculate the revenue requirement using the RCI based on the OEB's most recent inflation factor for distributors. This calculation is detailed in Section 2.1 of Exhibit H1, Tab 1, Schedule 1.
2) Derive new rates based on the updated revenue requirement, as outlined in Exhibit H1, Tab 1, Schedule 2 and Exhibit H1, Tab 1, Schedule 3.
3) Consistent with the requirements of IRM applications, Hydro One would also seek to update its Retail Transmission Service Rates and review and dispose of its Group 1 Deferral and Variance Account balances, as necessary.

In addition to the items listed above, Hydro One's 2021 application would seek the following adjustments:

1) Provide an updated load forecast along with the resulting billing determinants for 2021 and 2022.
2) Update the 2021 and 2022 capital factors based on the OEB's 2021 cost of capital parameters. The calculation of the capital factors is shown in Table 1 of Exhibit A, Tab 3, Schedule 2.
3) File an updated 2021 cost allocation model reflecting the changes above and that makes any necessary adjustments to the proposed rate design that arise (e.g. revenue-to-cost ratios).

Consumers Council of Canada Interrogatory # 16

Issue:

Issue 14: Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

Reference:

A-03-01-01

Interrogatory:

The evidence states that HON expects to continue to assess further opportunities to acquire other Ontario-based LDCs over the 2017-2022 business planning period. Please provide a list of any planned acquisitions and the timing of those acquisitions. Please explain how HON decides whether or not to pursue such acquisitions. What criteria are applied by HON? What are the key objectives of HON's acquisition policy?

Response:

As opportunities arise, Hydro One intends to continue to evaluate local distribution company consolidation possibilities in Ontario. Hydro One's acquisition criteria and objectives are out of scope of this Application.

Energy Probe Research Foundation Interrogatory # 12

Issue:

Issue 14: Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

Reference:

A-07-01 Page: 1-11

Interrogatory:

Please provide service area savings for the acquired utilities for 2017.

Response:

2017 year-end actual values are not available at this time. The values provided for 2017 'Hydro One Actuals'' are the forecast values provided in the June update. The tables below reflect these numbers.

Table 1: NPDI Service Area Savings

$/Million	2014	2015	2016	2017
OM&A				
Status Quo Forecast	5.7	5.8	5.9	6.0
Hydro One MAAD Application Forecast	5.8	2.6	2.7	2.7
Hydro One Actual	7.2	5.9	2.7	3.1
Projected Savings	(0.1)	3.2	3.2	3.3
Actual Savings	(1.5)	(0.1)	3.2	2.9
Capital				
Status Quo Forecast	5.0	4.7	4.6	4.4
Hydro One Forecast	3.1	2.9	2.9	3.0
Hydro One Actual	3.5	2.1	0.9	2.6
Projected Savings	1.9	1.8	1.7	1.4
Actual Savings	1.5	2.6	3.7	1.8

Table 2: HCHI Service Area Savings

$/Million	2015	2016	2017
OM&A			
Status Quo Forecast	8.2	8.3	8.5
Hydro One MAAD Application Forecast	6.4	4.4	4.5
Hydro One Actual	7.7	6.0	5.0
Projected Savings	1.8	4.0	4.0
Actual Savings	0.5	2.3	3.5
Capital			
Status Quo Forecast	6.4	6.1	5.4
Hydro One Forecast	4.2	3.2	3.3
Hydro One Actual	6.9	4.6	3.4
Projected Savings	2.2	2.9	2.1
Actual Savings	(0.5)	1.5	2.0

Table 3: WHSI Service Area Savings

$/Million	2015	2016	2017
OM&A			
Status Quo Forecast	3.9	4.6	4.0
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	1.7	2.2	1.6
Hydro One Actual (excluding overhead corporate costs)	4.2	3.8	2.1
Hydro One Actual (including overhead corporate costs)	N/A[1]	4.0	2.2
Projected Savings	2.3	2.3	2.4
Actual Savings (excluding overheads)	(0.3)	0.8	1.9
Actual Savings (including overheads)	N/A	0.6	1.8
Capital			
Status Quo Forecast	2.4	2.5	2.5
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	2.2	2.9	3.2
Hydro One Actual (excluding overhead corporate costs)	2.2	3.1	2.2
Hydro One Actual (including overhead corporate costs)	N/A[1]	3.2	2.3
Projected Savings	0.2	(0.5)	(0.7)
Actual Savings (excluding overhead corporate costs)	0.2	(0.6)	0.3
Actual Savings (including overhead corporate costs)	N/A	(0.7)	0.2

[1] As WHSI was not fully integrated into Hydro One's operations in 2015 it was essentially operating as "status quo". As a result, no corporate overhead costs were applied.

Vulnerable Energy Consumers Coalition Interrogatory # 15

Issue:
Issue 14: Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

Reference:
A-07-01 Page: 3 - Table 1

Interrogatory:
a) Please explain the significant underspending of capital in 2015 and 2016 in the NPDI service area.

b) Please explain how Hydro One has assured that this underspending will not impact reliability to customers in that service area?

Response:
a) The majority of the capital under spending in 2015 and 2016 for the NPDI service territory was in the area of line and pole refurbishment programs.

b) Hydro One uses a condition-based methodology to assess the risk of asset maintenance and/or replacement versus reliability impacts of no action in all of its distribution operations, including Norfolk. Specific to the line and pole refurbishment programs, which substantially show the areas of reduced spending, Hydro One determined that the forecast expenditures were not required in those years based on the assets current conditions, their assessed risk, and their impact on reliability levels.

The below table summarizes the reliability history in the Norfolk service area before, during and after the acquisition and integration of the former NPDI systems into Hydro One. The table's results confirm Hydro One's ownership has not resulted in a decrease in reliability and in fact, overall there has been a positive influence on customer's reliability experience in the area, since both SAIDI and SAIFI have remained at or below historical levels.

1 **Reliability – Norfolk Service Area**

	SAIFI (# interruption /NPDI Customer)	SAIDI (# interruption hours/NPDI Customer)	Notes
2012	1.19	1.78	
2013	1.32	2.04	
2014	2.65	3.5	
2015	0.43	1.27	Acquisition Year
2016	0.35	0.80	Integration Year
2017	0.60	2.15[i]	

2

[i] SAIDI was slightly elevated, but still below 2014 pre-acquisition levels, in 2017. This was mainly due to a major windstorm affecting much of south western Ontario, in March, 2017.

Building Owners and Managers Association Toronto Interrogatory # 63

Issue:
Issue 15: Is the proposed Earnings/Sharing mechanism appropriate?

Reference:
A-03-01-05 Page: 11

Interrogatory:
Why is the rationale for including CDM in a Z-factor when its capital says it is not included in the forecast?

Response:
In Exhibit A, Tab 3, Schedule 2, CDM is listed as an example of a government-mandated investment/policy that is out of Hydro One's control. Given the current regulatory mechanism available in the form of the LRAMVA, Hydro One would not seek Z-factor recovery related to CDM programs. Hydro One may seek Z-factor recovery in the future should a similarly impactful government-mandated investment arise.

Canadian Manufacturers & Exporters Interrogatory # 7

Issue:
Issue 15: Is the proposed Earnings/Sharing mechanism appropriate?

Reference:
A-03-02 Updated

Interrogatory:
With respect to the earnings sharing proposal:

a) Please explain why under a revenue cap mechanism Hydro One should retain the first 100 basis points of excess earnings.

b) Please confirm that the proposed sharing is asymmetrical. That is, if Hydro One under earns relative to the approved return on equity, Hydro One will not seek to recover any portion of the shortfall from ratepayers

c) Please confirm that the calculation of the actual ROE will be based on the same calculations and methodologies employed in a cost of service application. If this cannot be confirmed, please explain in detail any differences between the proposed ESM calculation of ROE as compared to that in a cost of service application.

d) What ROE will be used in the comparison to the actual ROE? For example, will it be the ROE that is built into rates for 2018, or will it change each year to reflect changes in the OEB's approved ROE?

e) Please confirm that Hydro One does not propose to "normalize" actual revenues to reflect the normal (or forecasted) degree days used to set base rates in 2018. If this cannot be confirmed, please explain in detail how Hydro One plans to normalize revenues.

f) Please explain why Hydro One proposes that any earnings sharing amounts that may accrue to ratepayers would not be cleared to them until Hydro One's next rebasing application.

g) Does Hydro One plan on filing annual applications to dispose of balances in other deferral and variance accounts?

h) What interest rate does Hydro One propose would be applied to amounts owed to ratepayers in the ESM deferral account?

Response:

a) Page 27 of the OEB's *Handbook for Utility Rate Applications* states that "utilities that achieve productivity improvements above what is expected are allowed to keep certain savings above the approved ROE." Hydro One notes that this approach is consistent with the 100 basis-point dead band for the earnings sharing mechanism that was approved by the OEB in the proceeding for Toronto Hydro's Custom IR application (EB-2014-0016).

b) Confirmed.

c) For the purposes of calculating actual ROE in the ESM, Hydro One intends to use a methodology similar to what is outlined in the OEB's RRR 2.1.5.6 template. The RRR 2.1.5.6 template is used by all Ontario distributors to report actual ROE to the OEB. In its calculation, Hydro One proposes to set the mid-year rate base to OEB approved levels in order to avoid double counting with amounts in the Capital In-service Variance Account proposed in Exhibit A, Tab 3, Schedule 2.

d) The ROE used in 2018-2020 will be the amount that is built in to rates in this proceeding. This ROE amount will be updated for 2021 and 2022 during the proposed mid-term update.

e) Confirmed.

f) Hydro One's approach is consistent with page 28 of the OEB's Handbook for Utility Rate Application which states that the assessment of earnings in an ESM should be based on the overall earnings at the end of the term consistent with the OEB's approach to limiting mid-term updates.

g) As stated in the response to Exhibit I-13-CCC-15, Hydro One will apply to dispose of its Group 1 deferral and variance account balances throughout the IR term, consistent with the OEB's policy for review of deferral and variance account balances outside of rebasing applications.

h) Hydro One proposes that the OEB's standard interest rate for deferral and variance accounts will apply to the ESM account.

OEB Staff Interrogatory # 64

Issue:

Issue 15: Is the proposed Earnings/Sharing mechanism appropriate?

Reference:

A-03-02 Page: 9 – Earnings Sharing Mechanism

Hydro One documents its proposed Earnings Sharing Mechanism as follows:

> *"Hydro One proposes to share with customers 50% of any earnings that exceed the OEB allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One Distribution's next rebasing. The calculation of the actual ROE for a test year will use the Board approved mid-year rate base for that period."*

Interrogatory:

Per the proposal in this application, Hydro One's next rebasing would be for rebased rates effective January 1, 2023. At the time of application, or even of a decision and rate order, audited actuals for 2022 may not be available. How is Hydro One proposing the clear the balance of the proposed ESM deferral account in this situation?

Response:

Hydro One proposes to clear the most recent audited actuals available at the time of its next rebasing application and would continue to track any remaining balances in the ESM deferral account for future disposition. For example, if audited actuals for 2022 are not available at the time of the OEB's decision, Hydro One will clear 2018-2021 balances at its next rebasing and continue to track 2022 amounts in the ESM deferral account for future disposition.

Building Owners and Managers Association Toronto Interrogatory # 68

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-04-01 Page: 2 lines 24, 25 Customer Service Strategy

Interrogatory:

a) Please describe each of the digital investments, when they were made, and how they have helped ensure valued service to customers, and which customers, their costs, capital and OM&A.

b) Please provide copies of the following surveys and reports:
   i. Examples of monthly Customer Satisfaction Transactional Survey;
   ii. The most recent Annual Customer Satisfaction Perception Survey for Commercial and Industrial customers;
   iii. Surveys or Reports of Call Centre Trends for Commercial and Industrial Customers, and steps to increase focus on Commercial and Industrial sector;
   iv. How many FTEs are in the "dedicated team" in the call centre for 2017, 2016, 2015, for 2018?
   v. Please provide the most recent Annual Report or its equivalent for the Hydro One Ombudsman.

Response:

a) Hydro One's Distribution Rate Application includes several digital investments to address customer feedback, as outlined below. Additional information can be found in the Investment Summary Documents referenced below:

   - Web & Mobile App (GP-16)
   - Customer Data and Analytics (GP-32)
   - Bill Redesign (GP-29)
   - Call Centre Technology (GP-28)

b)
   i. An example of Hydro One's monthly Customer Satisfaction Transactional Survey is provided Exhibit I-16-BOMA-068, Attachment 1.

ii. The most recent Annual Customer Satisfaction Perception Survey for Commercial and Industrial customers is provided in Exhibit I-16-BOMA-068, Attachment 2.

iii. Survey results for Hydro One’s Business Contact Centre is represented in the monthly Customer Satisfaction Transactional, b) (i) above.

iv. Approximately ten employees are dedicated to responding to Commercial and Industrial Customers within Hydro One’s Customer Contact Centre.

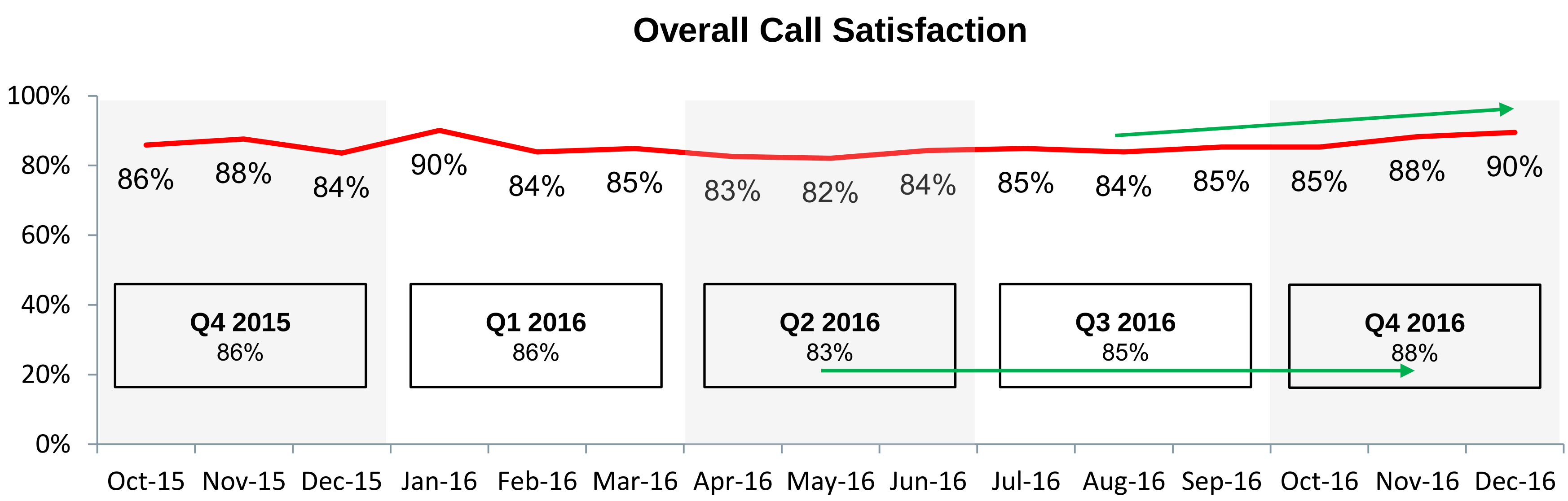
v. Please refer to Exhibit I-38-CCC-037, Attachment 1.

Executive Highlights Presentation

Contact Handling Transaction Satisfaction Tracking

Ending Quarter 4, 2016
Prepared by: Forum Research Inc.
January, 2017

Performance Management: Overall Satisfaction with the Call*

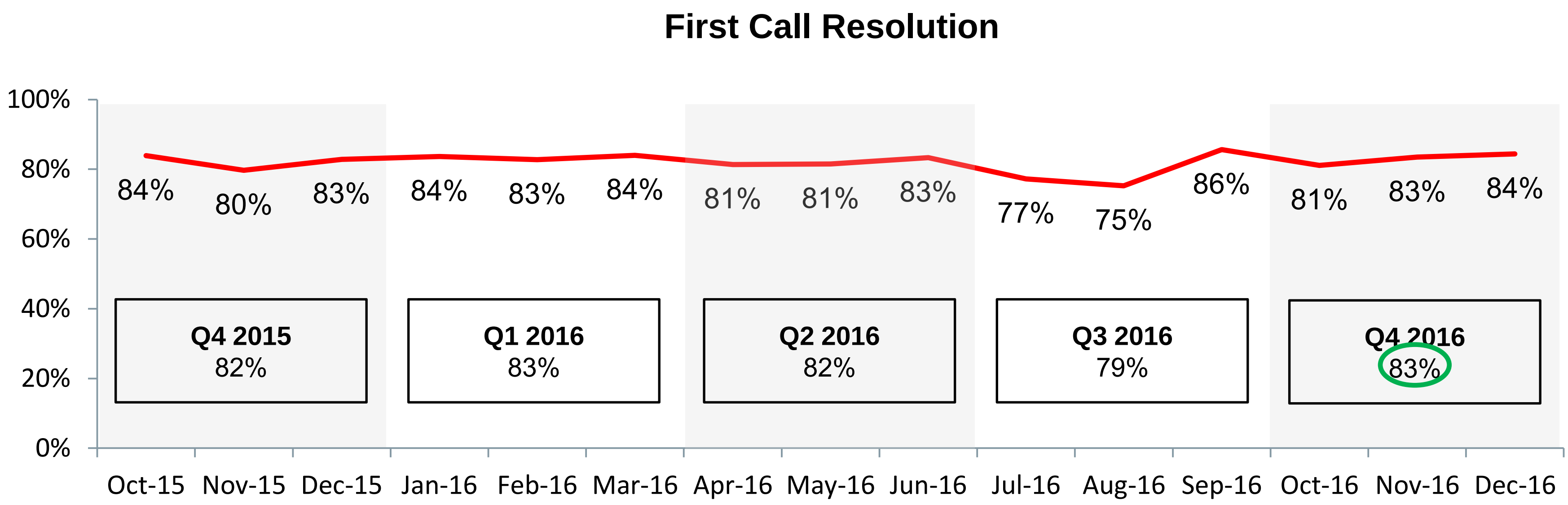


Key Insights

- *Overall satisfaction with the call has improved significantly from August to December.*
- *Overall satisfaction with the call has improved significantly from Q2/16 to Q4/16.*

Q3. How satisfied were you overall with this call to Hydro One?
*Note: Percentages represent scores of 4 and 5 on a 5-point scale

Performance Highlights: First Call Resolution*



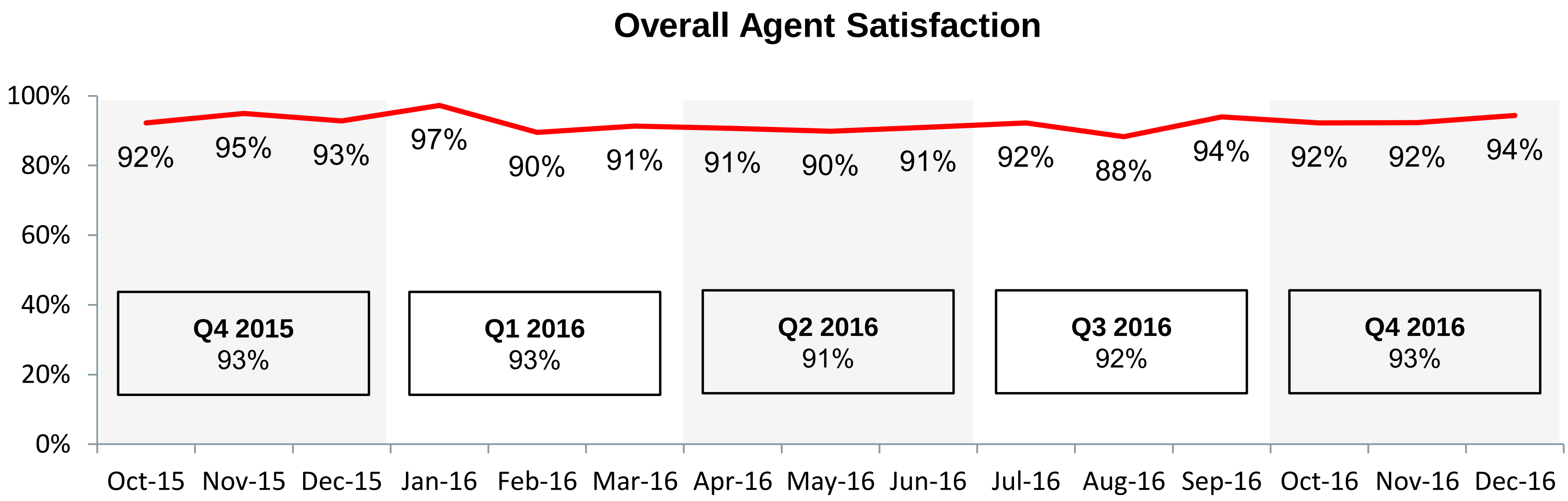
Key Insights

- *First Call Resolution in Q4/16 has improved significantly since Q3/16.*

Q10: "…once you did get through to an agent, on [DATE/TIME], was your issue resolved on the first call?...
*Note: Percentages represent % of respondents who answered "Yes"

*Note: LOB Request for Inclusion

Performance Highlights: Overall Satisfaction with Agent*



Key Insights

- *Overall satisfaction with the agent is statistically unchanged vs. Q3/16, and has remained relatively unchanged quarter-to-quarter.*
- *Overall Agent Satisfaction has remained relatively stable since February, after it's highest level in January.*

Q4r: "…thinking about this call on [DATE] at [TIME], how satisfied were you with the agent who handled your call?"
*Note: Percentages represent scores of 4 and 5 on 5-point scale

*Note: LOB Request for Inclusion

NORTHSTAR
Fearless Intellect™

hydro one

Customer Experience

Commercial Customer Satisfaction

Report of Findings

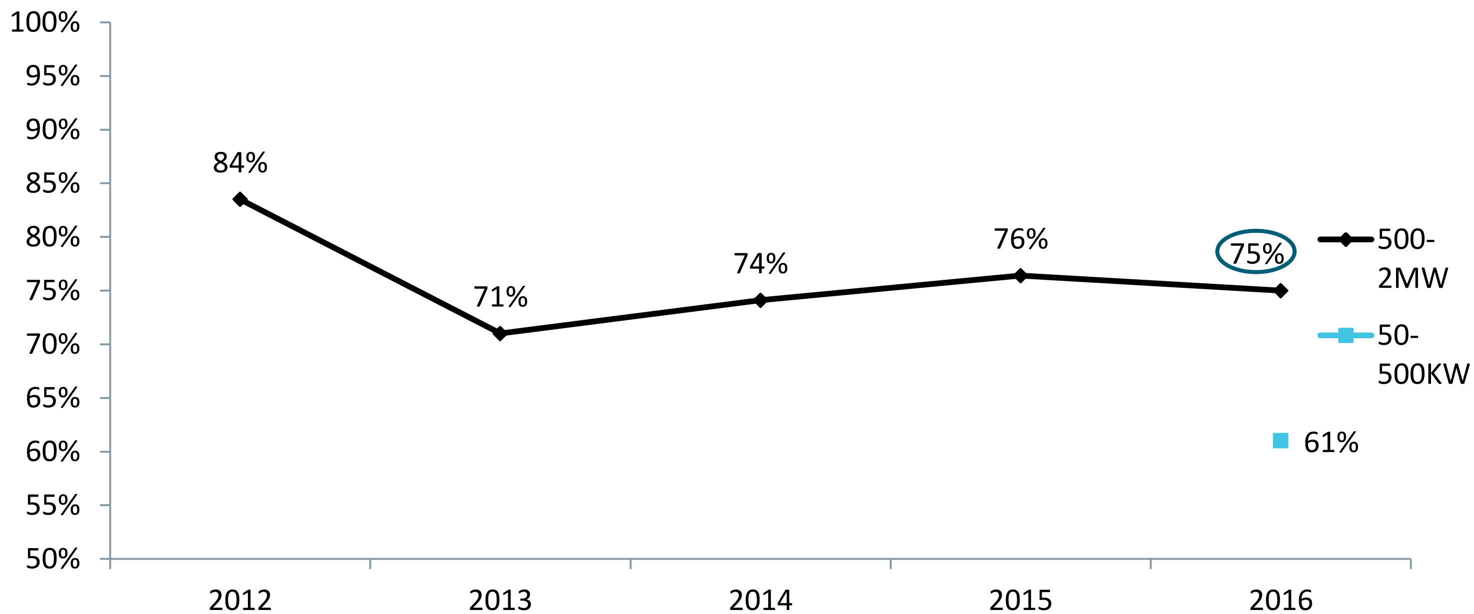
November 25, 2016

Overall Satisfaction – Survey Results

The survey question reads:

"How satisfied are you with Hydro One overall? Would you say you are…?"

Overall Satisfaction (T2B)

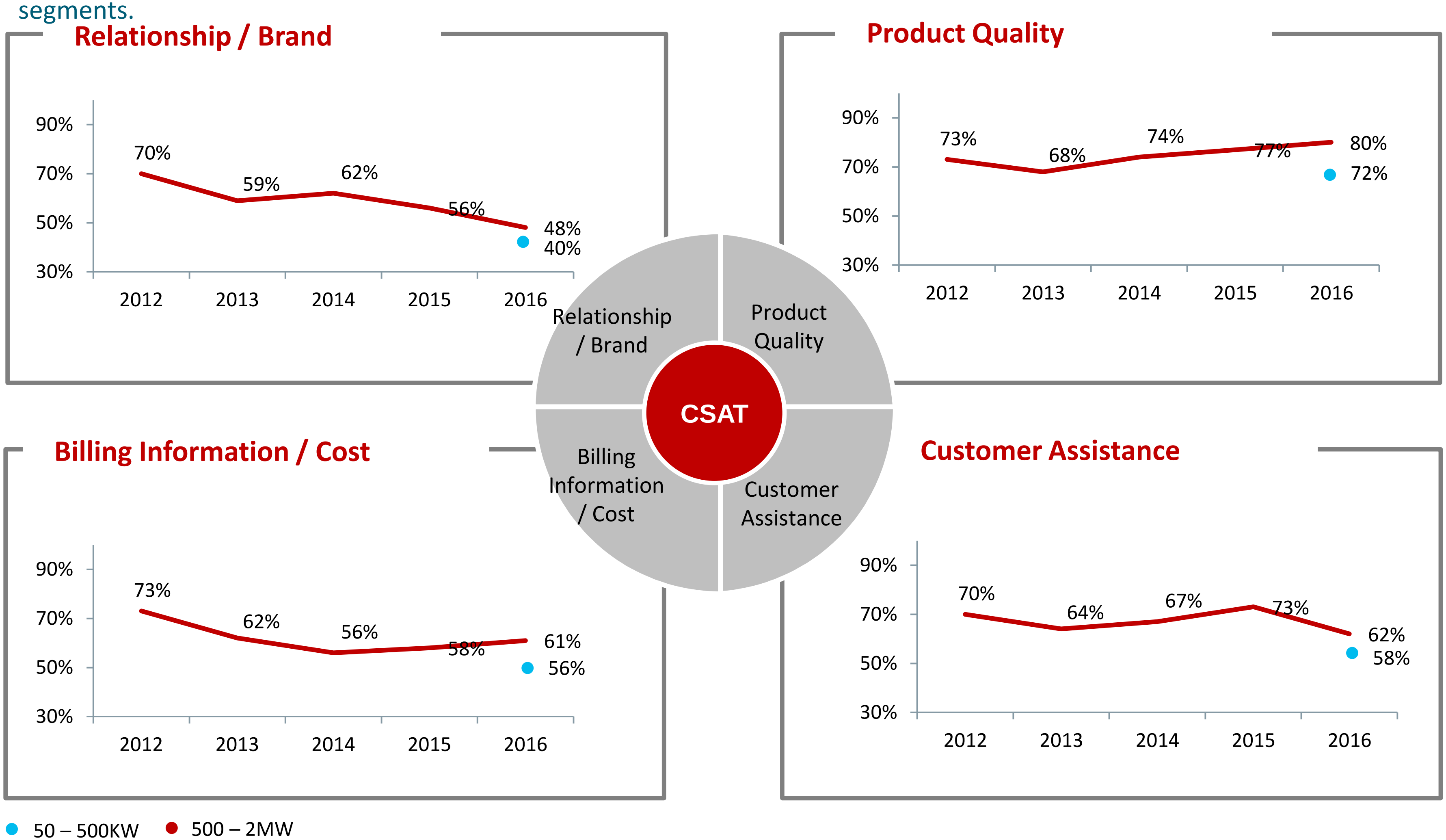


Key Insights

- *Overall satisfaction among 500 – 2MW customers remains on par with the last three waves.*
- *However, 50 – 500KW customers show a significantly lower level of satisfaction than their customer counterpart.*

Survey Findings: Drivers of Satisfaction

Northstar analyzed 500-2MW data from 2012 – 2014 using factor analysis to group attributes into the four common themes and key driver analysis to determine the key drivers of satisfaction using the Pearson Correlation technique. Below is a graphical representation of how Hydro One's performance has been trending for the past 5 years and between customer segments.



Building Owners and Managers Association Toronto Interrogatory # 69

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-04-01 Page: 7

Interrogatory:

What does the Company mean when it says "its Customer Strategy is in a period of transformation"? Please provide details.

Response:

As mentioned at the Hydro One Executive Presentation on Thursday, December 7, 2017, Hydro One is transitioning from a corporation wholly-owned by the Province to an investor-held utility with a strong focus on customer service. Hydro One has embraced a three-pronged approach that focuses on education, advocacy on behalf of customers, and responsiveness with respect to meaningful action that delivers value back to customers in a timely fashion. Additional information can be found on pages 31 to 54 of the transcript from the December 7th Executive Presentation.

Building Owners and Managers Association Toronto Interrogatory # 70

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-04-02 Page: 3

Interrogatory:

What was the attendance at the First Nations Engagement in early 2017? How many Chiefs and Heads of Regional Organizations? Where was the meeting held?

Response:

Hydro One hosted a province-wide First Nations Engagement Session in Toronto early February 2017. First Nations Chiefs from the communities that served by Hydro One Networks Inc., as well as the First Nations' Political Confederacy of Ontario, were invited to participate. Representatives from 71 First Nation communities attended the session.

Building Owners and Managers Association Toronto Interrogatory # 72

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
A-05-01 Page: 15

Interrogatory:
Are the call centre agents employees of Hydro One? If not, who is their employer? Are they all full time employees? If not, what percentage?

Response:
Hydro One's Contact Centre agents are employed by Inergi LP, an outsourced third party provider. Effective March 1, 2018, the Contact Centre agents will become Hydro One employees. Of the 380 agents, 40% are full-time, 20% part-time, and 40% hiring hall.

Building Owners and Managers Association Toronto Interrogatory # 74

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-05-01 Page: 23

Interrogatory:

a) Why would customer satisfaction be lower in 2015 than in 2014 due to events in the 2016 data?

b) Please explain: paperless billing notification, my account, self-serve portal.

c) What is the impact on customer satisfaction of each of these?

d) How many customers, in each rate class, are on e-billing? What are the targets over the plan period for increasing that percentage?

e) What ability do HONI's customers with smart meters have to issue outage claims, and accept "restart notices"? Does Hydro Inc. plan to put these features in place? Has Hydro One Distribution looked at practices at other distributor sales (Alectra) or Veridian? How do they differ?

Response:

a) As outlined in Exhibit A, Tab 5, Schedule 1, customer satisfaction remained consistent in 2014 and 2015 at 85% and declined to 84% in 2016. Customer Satisfaction with Agent Handled Calls and My Account both increased due to Hydro One's increased focus on customer service with call centre agents and improvements to Hydro One's My Account self-service portal. The decline in 2016 was mainly attributable to a marginal decline in the Outage Handling component.

b) Additional information can be found in the Investment Summary Documents referenced below:

- paperless billing notification (GP-32)
- my account (GP-16)
- self-serve portal (GP-16)

c) Collectively, the investments discussed in Exhibit A, Tab 5, Schedule 1, pp. 23-25 are expected to improve customer satisfaction to the 2022 target of 89 per cent. These investments will ensure that existing services continue to be maintained and new functionality will be delivered to customers to support evolving customer needs and preferences, thereby improving overall customer satisfaction.

d) Refer to Exhibit I-38-Staff-201, parts b), and d).

e) In order to report an outage, Hydro One customers must contact the Customer Contact Centre. An investment in Self-Service Technology (as outlined in GP-16) will provide customers the ability to report power outages online or via the mobile app, which will improve customer service and reduce operational cost. Several investments are also proposed for large customers, as outlined in Exhibit I-23-Staff-077.

Hydro One is unfamiliar with the term "restart notices". Hydro One does not understand which practices at other distributors the question is referring to.

Building Owners and Managers Association Toronto Interrogatory # 89

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
A-07-01 Page: 10

Interrogatory:
What is meant by line 18, where the evidence states that "Both of the actual and forecast amounts provided disputed incremental costs only". Please explain fully, and describe the purpose of Table 4.

Response:
The quoted line should have read:

"Both of the actual and forecast amounts provided depict incremental costs only"

This means that the tables showing the cost to serve the acquired customers include only costs incremental to Hydro One's operation. An allocation of overhead cost was not included, as overhead costs would have been incurred by Hydro One at the same level, regardless of whether or not the acquisitions had occurred.

The purpose of Table 4 is to provide the last approved OM&A for each of the Acquired Utilities, actual OM&A for 2014 to 2016, and forecast OM&A for 2017 and 2018. Refer to Exhibit I, Tab 7, Schedule BOMA-88 for further detail.

Building Owners and Managers Association Toronto Interrogatory # 90

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1

Interrogatory:
To what extent do investments and OM&A support performance customer feedback on needs and preferences?

Response:
Please see section 1.3.4 of the DSP (Exhibit B1, Tab 1, Schedule 1) entitled “How the Plan Reflects Customer Needs and Preferences” and Exhibit I-23-EnergyProbe-31.

Building Owners and Managers Association Toronto Interrogatory # 92

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1 Page: 15

Interrogatory:

Details of water expenditures in 2022.

How are distribution, transmission capital projects:

- assessed
- do the same planners deal with transmission and distribution projects?
- how much of capital plant is capital contribution to transmission?

Response:

Hydro One does not understand the reference made: “Details of water expenditures in 2022.”

Capital projects are assessed using the process detailed in the DSP section 2.1, “Investment Planning Process.” (See page 2360 of 2930.)

Planners are typically dedicated to either transmission or distribution projects, but not both.

The capital contributions from Hydro One Distribution to Hydro One Transmission over the period 2017 to 2022 total $8.9 million. See the following references from section 3.8 of the DSP:

- Leamington TS, $2.2 million (ISD GP-25);
- Hanmer TS, $3.7 million (ISD GP-26); and
- Enfield TS, $3.0 million (ISD GP-27).

Building Owners and Managers Association Toronto Interrogatory # 93

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 1439

Interrogatory:
Which agreements were reached? Please list the agreements Please submit copies of any agreements reached.

Response:
The interrogatory appears to be referencing section 1.3.2.1 of the DSP ("Principles and Design"), which describes the principles and objectives Hydro One used to guide its stakeholder engagement design and implementation.

No agreements were reached during stakeholder engagement process.

Building Owners and Managers Association Toronto Interrogatory # 94

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 1448

Interrogatory:
Please provide a copy of the "session report" from engagement session with Métis Nation of Ontario.

Response:
Please refer to Exhibit I-6-Anwaatin-1, Attachment 8 for a copy of the session report from engagement session held with the Métis Nation of Ontario on May 13, 2017 in Toronto.

Building Owners and Managers Association Toronto Interrogatory # 95

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 1449 lines 9-14

Interrogatory:

a) Given the reluctance to increased rates expressed by residential and small commercial customers, why is HONI Distribution not proposing an option which would leave rates flat, for part or all of the period? Same reaction from large customers.

b) To what extent has HONI responded to large customers' requests for additional capacity? Please provide reference to project that are in response to these requests.

Response:

a) Because of the impact of the updated load forecast, a zero percent rate increase scenario is not possible. Please see part c) of Exhibit I-35-BOMA-B31 and section 2.4 of the DSP (Exhibit B1, Tab 1, Schedule 1), lines 16-18 (page 2496 of the DSP) for reasons why “Plan C” is not acceptable.

b) Please see Exhibit I-16-BOMA-B118. Investments addressing load growth are outlined in section 3.8 of the DSP (Exhibit B1, Tab 1, Schedule 1) ISD-SS-02 (System Upgrades Driven by Load Growth), some of which are in response to requests for additional capacity from large customers.

Witness: BRADLEY Darlene

Building Owners and Managers Association Toronto Interrogatory # 96

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Issue 22: Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

Reference:

Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 87

Interrogatory:

Small business survey has 144. What is the margin of error? Most ________________ 200. Some had 144.

Response:

With regards to the Customer Engagement process, survey participants did not have to respond to all questions, which is why the sample sizes varied (i.e. Q11 n=144 and Q03 n=200).

With respect to the Small Business sample size of 200 customers, the margin of error was ± 6.9 percentage points. Please refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 1.3, Attachment 1, Distribution Customer Engagement Report for more details.

Witness: LISTER Warren

Building Owners and Managers Association Toronto Interrogatory # 97

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 88

Interrogatory:
Were the customers asked how much of an increase they would accept to reduce ratio and length of outage or maintain the number of outages (see earlier question) about one percent?

Response:
Small business customers were asked the following two questions:

- Would you be willing to pay anything higher than $ 5.20 or about 1% more on your total monthly bill if it meant you would have better reliability than you have now?

- Would you be willing to pay anything higher than $ 5.20 or about 1% more on your total monthly bill if it meant you would have better customer service than you have now?

Small business customers were not asked for a specific increase amount that they would accept.

Building Owners and Managers Association Toronto Interrogatory # 98

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 89

Interrogatory:
What was the purpose of the question on renewable energy, given that it is a stated first priority?

Response:
As more renewable energy products go online, the distribution system will need to be upgraded to connect customers. The purpose of this question was to understand customer preference for when and how upgrades would happen, as this work would impact rates.

Building Owners and Managers Association Toronto Interrogatory # 99

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Issue 22: Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

Reference:

Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 90

Interrogatory:

The words "rate" and "bill" appear to be used interchangeably in this page. Please explain why, and what is meant by the title, question, and supplementary discussion, monthly bill, or rate?

Response:

A customer's bill contains more than just Hydro One's Distribution Delivery Costs. The "rate" increase references Hydro One's Distribution Delivery Cost line item. The "bill" increase references the impact to the customer's overall bill, which include electricity usage, regulatory charges, taxes, etc.

Building Owners and Managers Association Toronto Interrogatory # 101

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Issue 22: Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

Reference:

Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 123

Interrogatory:

a) What importance do you attach to the results which are insignificant only because of small sample size?

b) Why were not the sample sizes of LOA and Commercial and Industrial increased?

Response:

a) Hydro One considers all feedback, regardless of the source (ie. online or in person) or sample size.

b) All LDA and Commercial and Industrial customers were invited to participate. Customers who were not able to attend a workshop were invited to submit a response to a survey online.

Building Owners and Managers Association Toronto Interrogatory # 102

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 123

Interrogatory:

a) Which specific uses of technology are you referring to in the "Reliability Improvements" question to reduce your chances of losing power?

b) Grid Strengthening category. What specific customer technologies or priorities or resources are you referring to, to "enable the grid to better withstand summer weather"?

c) Rapid Response on Progress and Monitoring and Control. What technology, retrofits, practices are you referring to here? Perhaps use examples to explain how they work and what their impact would be on SAIFI and SAIDI (qualitatively at least).

Response:

The answers below refer to Exhibit B1, Tab 1, Schedule 1, DSP Section 1.3, Attachment 1, Distribution Customer Engagement Report.

a) Employing distribution automation can "reduce your chance of losing power" using communications and control technology to remotely detect faults and provide sectionalization and isolation to minimize the impact and duration of outages on the distribution system.

b) Grid Strengthening will "enable the grid to better withstand severe weather" through the implementation of distribution system equipment designs and/or standards that will make the distribution system more resistant to major storm events, which include high winds, lightning and heavy snow and ice. Solutions could include rebuilding overhead lines designed to withstand higher wind and ice loads and implementing more aggressive forestry management.

c) The Rapid Response Program is a strategy that focuses on improving the response time to restore and limit the scope of distribution outages such as utilizing monitoring to help locate the source of an outage and allow for quicker restoration.

Building Owners and Managers Association Toronto Interrogatory # 103

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1 Attachment 1 Page: 123

Interrogatory:
What do customers mean when they complain about the format and presentation of bills?

Response:
Feedback received from LDA, Local Distribution Companies, Distributed Generation customers, and Commercial and Industrial customers indicated that the bills were sometimes difficult to understand, specifically how line item content was presented within the bill.

Building Owners and Managers Association Toronto Interrogatory # 106

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 125

Interrogatory:
Commercial and Industrial holdback issue. What is your interpretation of that?

Response:
Commercial and Industrial customers are more sensitive to rate increases over other segments, including LDA, Local Distribution Companies, or Distributed Generation customers.

Building Owners and Managers Association Toronto Interrogatory # 109

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Issue 22: Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page: 130

Interrogatory:

Majority of respondents (129) didn't accept a rate increase of any size, whether reliability remains the same or improves.

Response:

This interrogatory does not pose a question.

Building Owners and Managers Association Toronto Interrogatory # 117

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page 139

Interrogatory:

What is Hydro One doing about bills to regional offices, rather than head offices? What does Hydro One do to ensure the municipal industrial cost sharing for connection and system expansion?

Response:

Hydro One does not understand the question.

Building Owners and Managers Association Toronto Interrogatory # 118

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page 140

Interrogatory:

What is your reaction to the claim that you are not concentrating on new capacity to serve growing customers fast enough? Please discuss.

Response:

Hydro One is mandated by the OEB to plan and build the distribution system for reasonable forecast load growth, see section 3.3 Enhancements of the Distribution System Code. Distribution system investments that are proposed to accommodate load growth are explained in section 3.8, ISD SS-02 System Upgrades Driven by Load Growth of the DSP. Hydro One is also mandated to connect any new customer loads, however, the cost recovery model to add new capacity for increased loads from large individual or groups of customers is also governed by the OEB and is explained in section 3.2 Expansions of the Distribution System Code.

Building Owners and Managers Association Toronto Interrogatory # 119

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page 143

Interrogatory:
How do you respond to the comment that rates for ratepayers while paying a large divided is considered unethical by large customers.

Response:
Hydro One's rates reflect the cost to serve its customers, including an appropriate cost of capital as approved by the OEB.

Building Owners and Managers Association Toronto Interrogatory # 120

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1 Page 144

Interrogatory:

What is HONI doing to provide more information on outages on a regular basis?

Response:

Customers can receive information on outages through a variety of mechanism. Hydro One's outage app provides details on any planned and unplanned outages in our service territory. This app has been downloaded over 340,000 times. Similar information is also provided through an outage map on HydroOne.com.

Hydro One also offers proactive outage notifications to customers who subscribe. Customers can receive either a text message or email notification when their power is out, and receive regular updates on the estimated time of restoration.

Please refer to Exhibit A, Tab 5, Schedule 1, s.3.6 Customer Satisfaction: Customer Satisfaction Survey Results, p.24, lines 16 to 25 for a discussion on Outage Handling.

Witness: LISTER Warren

Building Owners and Managers Association Toronto Interrogatory # 121

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 1 Page 145

Interrogatory:
What changes does Hydro One propose to make in the next customer engagement program to reflect concerns, eg. more detail on historical costs, specific type of costs, cost effectiveness?

Response:
Hydro One will use feedback received from the OEB and these proceedings to inform its future Distribution Customer Engagement activities.

Consumers Council of Canada Interrogatory # 17

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-03-02 Page 2

Interrogatory:

The evidence states that one advantage of the RCI approach provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the Seasonal Rate Class over the 2018-2022 Custom IR term. What is the current status of the OEB Decision's to eliminate the Seasonal Class? Please file all correspondence between the OEB and HON regarding this issue. If the OEB determined that HON should proceed with the elimination of the Seasonal Class, what process would HON follow to comply the Decision?

Response:

The Board issued a Notice of Proceeding and Procedural Order #1 under EB-2016-0315 on November 3, 2016 and updated on November 10, 2016. On December 1, 2016 Hydro One provided an update to the August 4, 2015 "Report on Elimination of the Seasonal Class" that addressed the items raised by the Board in PO#1, and also filed a draft Notice of Proceeding as requested in PO#1. Hydro One is awaiting direction from the Board on next steps with regards to proceeding EB-2016-0315.

There has been no official correspondence with the Board on this issue other than an email exchange with Board staff seeking to clarify some details in the updated Report. The e-mail exchange is provided as Attachment 1 to this response.

The process to comply with the Decision would depend on the details of the Decision, but as a minimum, Hydro One would need to update its information on the number of Seasonal customers that would move to the UR, R1 and R2 rate classes and then update its cost allocation and rate design models to set the rates for the new rate class structure.

CLEVERTON Anthony

From:	ANDRE Henry
Sent:	Wednesday, June 21, 2017 3:44 PM
To:	'Harold Thiessen'
Cc:	Jennifer Lea
Subject:	RE: Seasonal Rates Elimination and Impacts

Harold,

Link many other things in life, the bill impacts as a result of eliminating the seasonal class and moving to fully fixed-rates is a matter of perspective and each customer's individual situation (consumption). For example, you say at the bottom of your email that you expected that "the further you move toward fully fixed in Seasonal the impacts of elimination should show to be less." In fact that is the case, for low volume Seasonal customers, where as per the information below, moving from current Seasonal rates to fully fixed R2 rates results in a 177% impact, while moving from fully-fixed Seasonal rates to fully fixed R2 rates the impact is only 83% (which is what you were expecting). The reverse is true for high volume Seasonal customers, which is perhaps the example you were thinking of when you said "why does move to all fixed make the impacts of the class elimination worse?".

I did a have a comment regarding how the information has been extracted and is presented below. Currently the data below shows two things for each rate class: 1) The impact of moving from fully-fixed seasonal to fully-fixed year round residential (the first two columns) and 2) the impact of moving from current bill to fully-fixed year round residential (columns 3 and 4).

Again, this is perhaps a matter of perspective, but wouldn't it be more helpful to show customers the impact of moving from 1) their current bill to fully-fixed seasonal rates and 2) their current bill to fully-fixed year round residential rates. The information required to present it this way is what is shown in Table 9. Taking low volume seasonal moving to R2 as an example, this approach would show that their current bill of $50.96 will go to $76.85 (a 51% increase) as a result of moving to fully-fixed Seasonal rates (a change the Board has already approved) and that their $50.96 current bill will go to $141.09 (a 177% increase) as a result of eliminating the Seasonal class and moving to fully-fixed R2 rates (the subject of this proceeding). That way these customers can see that on top of the 51% increase that is coming, their bill will further increase by 126% (177-51) as a result of eliminating the seasonal class. By the way, this 2 step change is what is illustrated in Table 10.

Note sure if this fully addresses your question, but hope it helps.

Henry Andre
Director, Regulatory Affairs – Pricing & Compliance, TCT07
Hydro One Networks Inc.
Tel: (416) 345-5124
Cell: (647) 409-3198
Email: henry.andre@hydroone.com

From: Harold Thiessen [mailto:Harold.Thiessen@oeb.ca]
Sent: Thursday, June 08, 2017 4:25 PM
To: ANDRE Henry

Cc: Jennifer Lea
Subject: Seasonal Rates Elimination and Impacts

Hi Henry:

I am looking at your updated report again, and need to get a handle on what the most appropriate numbers to use in the potential notice for this case.
My summary is shown below, but I do have a question at the bottom of this page.

For pages 11 – 15:

<u>Seasonal Customers who are assigned to the UR class (271)</u>, will see their total bill
decrease compared to staying in the Seasonal Class (with the move to all fixed distribution rates complete).
And, Average and High Consumption customers will also experience a decrease from current bills.

Monthly Bill: Seasonals moving to UR All Fixed All
Fixed Current All-Fixed UR
Seasonal Rate UR Rate 2016 Bill over
Current Bill

Low consumption (50 kWh/month) $ 77 $ 46 -40.2% $50.96 -
9.8%
Ave. consumption (350 kWh/month) $124 $ 92 -
25.8% $124.09 -25.9%
High consumption (1000 kWh/month) $227 $192 -
15.0% $282.53 -32.0%

<u>Seasonal Customers who are assigned to the R1 class (71,000)</u>, will see their total bill
decrease compared to staying in the Seasonal Class (with the move to all fixed distribution rates complete).
And, Average and High Consumption customers will also experience a decrease from current bills.

Monthly Bill: Seasonals moving to R1 All Fixed All
Fixed Current All-Fixed R1
Seasonal Rate R1 Rate 2016 Bill over
Current Bill

Low consumption (50 kWh/month) $ 77 $ 70 -
9.1% $50.96 37.4%
Ave. consumption (350 kWh/month) $124 $117 -
5.6% $124.09 -5.7%
High consumption (1000 kWh/month) $227 $218 -
4.0% $282.53 -22.8%

<u>Seasonal Customers who are assigned to the R2 class (84,000)</u>, will see their total bill
increase in all consumption levels, compared to staying in the Seasonal Class (with the move to all fixed distribution rates complete).
But, high users will show just a slight increase from existing rates.

Monthly Bill: Seasonals moving to R2 All Fixed All
Fixed Current All-Fixed R2

	Seasonal Rate	R2 Rate		2016 Bill	over Current Bill
Low consumption (50 kWh/month)	$ 77	$141	+83.1%	$ 50.96	177.7%
Ave. consumption (350 kWh/month)	$124	$189	+52.4%	$124.09	52.4%
High consumption (1000 kWh/month)	$227	$293	+29.1%	$282.53	3.9%

Now Table 8 shows that the Elimination of the Seasonal Class would not be as severe if using the 2017 Elimination impacts against the Current 2016 Bills.
So it appears that the move to end-state fully fixed actually makes the incremental impact of the elimination of the seasonal class worse.

However, my understanding is that the move to all fixed reduces within-class subsidy. So the further you move toward fully fixed in Seasonal the impacts of elimination should show to be less.
But why does move to all fixed make the impacts of the class elimination worse?

Harold

Consumers Council of Canada Interrogatory # 18

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-03-02 Page 11

Interrogatory:

What is HON's proposal regarding a materiality threshold for Z-Factor relief? What process is HON proposing to deal with Z-factors (e.g., annual filing)?

Response:

Hydro One proposes to use a materiality threshold of $1 million for Z-factor relief, consistent with methodology outlined in section 2.0.8 of Chapter 2 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications*. Should the need arise, Hydro One expects that it would seek to include any request for approval of a Z-factor as part of its next annual update application.

Canadian Manufacturers & Exporters Interrogatory # 10

Issue:
Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:
A-03-02 Updated

Interrogatory:
a) Please confirm that Hydro One is proposing a materiality threshold of $1 million for the Z-factor. If this cannot be confirmed, please provide the proposed materiality threshold proposed by Hydro One.

b) Is Hydro One proposing that the Z-factor also be available for the 2018 re-basing year? If so, please explain where in the current Filing Requirements for Electricity Distribution Rate Applications this is noted as being available in the cost of service/rebasing test year.

c) Please confirm that the materiality threshold is based on the revenue requirement impact with any material, unexpected cost. If this cannot be confirmed, please explain why it is not based on the revenue requirement impact.

d) Hydro One has defined a Z-factor as an event that is associated with material, unexpected costs. Would a Z-factor event also be triggered by a material, unexpected reduction in costs (such as a reduction in tax rates or increase in CCA rates)? Please explain fully.

e) Would an unexpected material increase or decrease in revenues be eligible for consideration as a Z-factor event? Please explain fully.

Response:
a) Confirmed in Hydro One's response to Exhibit I-16-CCC-18.

b) Hydro One is proposing that the Z-factor is available in all five years of the Custom IR period. As stated in Section 2.6 the OEB's *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* ("the Report of the Board"), issued July 14, 2018, "Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application."

c) Confirmed.

d) Hydro One has proposed to use the Z-factor mechanism, as defined by the OEB in Section 2.6 of the Report of the Board. In that report, the OEB states that Z-factors provide recovery of costs "to a distributor" for unforeseen events outside of management's control. It is highly unlikely that Hydro One would file a Z-factor in the event of a material, unexpected reduction in costs. Rather, ratepayers would share in the benefit of any reduction in costs through the Capital In-service Variance Account and Earnings Sharing Mechanism that are proposed in Exhibit A, Tab 3, Schedule 2.

e) Based on Hydro One's understanding of the Report of the Board, the Z-factor would be available in an instance of a material change in revenues provided that Hydro One can demonstrate that the event meets the three criteria of causation, materiality and prudence, as outlined by the Report of the Board.

OEB Staff Interrogatory # 65

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-03-02 Page: 12 – Off-ramp

Interrogatory:

Please confirm whether the ROE would be calculated on the regulated Distribution operations of Hydro One, or for Hydro One on a consolidated Distribution and Transmission basis.

Response:

The ROE would be calculated on the basis of Hydro One's regulated distribution operations only.

Witness: D'ANDREA Frank

Vulnerable Energy Consumers Coalition Interrogatory # 16

Issue:

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Reference:

A-03-02 Page: 11

Interrogatory:

a) Hydro One lists Smart meters or similar type programs as a potential z-factors. Please clarify is this is meant to cover the normal replacement of meters for the residential and GS<>50 classes? If it is please explain how normal meter replacement would qualify as a z-factor.

Response:

a) This is not meant to cover normal replacement of meters. As stated on page 11 of Exhibit A, Tab 3, Schedule 2, "investments that are government-mandated or otherwise outside of management's control" would qualify for a Z-factor. Smart meters are provided as an example of such government driven investments.

Witness: D'ANDREA Frank